Wildlife Commission Resolution – Forbes Trinchera Ranch

Whereas the Forbes family purchased the Trinchera Ranch in 1969;

Whereas the Forbes family initially maintained the property as a working ranch and to this day continues to lease portions of the Ranch for grazing, but over the years has concentrated on transforming the Ranch into a wildlife property that has few, if any, equals in the United States;

Whereas the Forbes family, at their own expense and initiative, has engaged in preserving and improving tens of thousands of acres of valuable wildlife habitat on the Ranch, which has not only helped to support the numerous populations of game and nongame wildlife species that exist there, but has also assisted in avoiding game damage on neighboring agricultural lands by maintaining those populations on the Ranch;

Whereas the Forbes family allowed the construction of miles of fence on their property along State Highway 160, which has not only protected wildlife, but has also helped to prevent the loss and damage to human life and property associated with wildlife-vehicular accidents;

Whereas the Forbes family proposed and funded the transplantation of bighorn sheep, Colorado's state animal, to the Ranch and have continuously supported that herd's development into one of the largest and most valuable herds in the State;

Whereas the Forbes family provided financial and logistical support for graduate student research on elk behavior in cooperation with the Colorado Division of Wildlife and on range condition assessments with Colorado State University;

Whereas the Forbes family was instrumental in the preservation of the Rio Grande Cutthroat trout population on the Ranch and throughout its historic range, helping not only to ensure the continued existence of that species in Colorado, but also providing fish for transplantation into New Mexico;

Whereas the Forbes family donated a 81,000-acre conservation easement, the largest conservation easement in Colorado history to *Colorado Open Lands*, which will help ensure the continuation of the wildlife legacy the family created for the Ranch;

Whereas the Forbes family has worked with the Colorado Division of Wildlife to allow public hunting through the *Ranching for Wildlife* program, as well as generously allowing the use of the Ranch for numerous special events and programs that encourage public participation in outdoor recreation;

Whereas throughout their transformation of the Ranch into the wildlife property it currently is, the Forbes family has been assisted by wildlife management skills of the Ryland family, who must be recognized as an important part of the Ranch's successes; and

B-010-001: Comment Noted (In Review)

Your email/letter/comment form has been received and your comment noted.

The Environmental Impact Statement is anticipated to be completed in late 2010 and will be available at http://www.usda.gov/rus/water/ees/ea.htm.

Wildlife Commission Resolution – Forbes Trinchera Ranch

Whereas when the time came for the Forbes family to leave the Ranch, they found an equal steward for the Ranch's incredible wildlife resources, the Bacon family, who have pledged with the assistance of the Ryland family to continue the Forbes family's outstanding traditions of conservation, habitat protection and improvement, and hunting and fishing that have become the recognized trademark of ownership of the Ranch;

Therefore be it resolved that the Colorado Wildlife Commission wishes to express its deepest gratitude and respect for all of the efforts of the Forbes family. Over the years the Forbes family has proven that there can be no better friend to Colorado's wildlife.

Be it further resolved that the Colorado Wildlife Commission wishes to also express its gratitude for the emergence of the Bacon family and their pledge to continue the efforts of the Forbes family. Truly, the Forbes family has found the appropriate successor to continue the wildlife legacy of the Trinchera Ranch that is so valuable to the State of Colorado, her citizens and visitors.

Be it further resolved that the Colorado Wildlife Commission directs the Colorado Division of Wildlife to assist the Bacon family in their efforts to continue the wildlife legacy of the Trinchera Ranch and to secure its position as a destination for discerning recreationists, conservationists, hunters, wildlife watchers, and all those who treasure the wildlife resources of the State of Colorado.

Adopted July 10, 2008

Robert W. Bray

Robert Bray

Chairman
Colorado Wildlife Commission

News about Colorado's Natural Resources

Email Article

2/8/2005
Division of Wildlife

PRIVATE RANCH FINDS BENEFITS IN WORKING WITH DOW ON SHEEP PROJECT

The DOW and a large ranch in the San Luis Valley are buidling on a cooperative relationship that serves wildlife statewide.

When the Colorado Division of Wildlife (DOW) needed bighorn sheep to restore the animal to the Mount Zirkel Wilderness Area near Walden, the Forbes Trinchera Ranch in southern Colorado was happy to offer to help.

A large herd of bighorn sheep live on the Forbes ranch, but is starting to outgrow the available habitat.

Trapping operations at the Forbes over the past two weeks have captured 41 sheep that have been relocated more than 300 miles to the north.

"We got some of our sheep years ago in a similar transplant operation," said Forbes Trinchera ranch manager Ty Ryland. "Our local herd has done so well that we're actually sending out more bighorns than were brought in to start the population in the early 1990s."

Over the past month, Forbes' staff members have worked with the DOW to trap sheep for transplant. But the ranch's commitment to the project goes further than just giving up sheep.

"Ty and the Forbes Trinchera staff have been great to work with," said Tom Spezze, DOW southwest regional manager. "Beyond giving us access to the sheep, they plowed roads, baited traps, hung nets, and helped physically catch the sheep."

"Trapping a large number of sheep is a major operation," added Bruce Watkins, DOW terrestrial biologist for the southwest region. "For the protection of the animals, you need enough people to get to each animal quickly when the net is dropped to make sure the sheep are restrained and safe."

The sheep trapped on the Forbes Trinchera Ranch generally winter on the lower Forbes and spend the warmer seasons in the nearby mountains. Beyond just providing sheep for the new herd, the trapping operation also helps the existing herd.

"We're at the carrying capacity of what our bighorn winter range will support, so giving the sheep to establish a herd somewhere else is a great management tool," said Ryland. "Not only does this herd remain healthier, the citizens of Colorado benefit by getting another population of these magnificent animals."

The Forbes Trinchera Ranch has been involved with the DOW for a number of years. The ranch is enrolled in the DOW's Ranching for Wildlife program, which encourages large landowners to manage their lands for wildlife benefits. The Ranching for Wildlife program was established by the Colorado Wildlife Commission in 1985 and has opened more than a million acres of prime private land for limited public hunting.

Ryland serves on the local Mt. Blanca Habitat Partnership Program committee. The Habitat Partnership Program is designed to help alleviate crop, rangeland forage and fence conflicts between big game animals and livestock on private and public lands.

In addition to bighorn sheep projects and big game habitat improvements, the Forbes Trinchera staff has worked with DOW aquatic biologists to improve stream habitat for cutthroat trout.

Discussions are also occurring to see if the ranch can assist with other species protection and recovery projects.

"Wildlife is the single biggest thing we do at the ranch," Ryland emphasized. "Last year we were able to sign a conservation easement to protect 81,000 acres. We're glad to be working on a wildlife legacy that will last in perpetuity."

Division of Wildlife

Previous

STATE OF COLORADO

OFFICE OF THE GOVERNOR
136 State Capitol Building
Denver, Colorado 80203
(303) 866 - 2471
(303) 866 - 2003 fax

Bill Ritter, Jr.
Governor

July 21, 2008

Forbes Family
Trinchera Ranch
PO Box 149
Fort Garland, CO 81133

Dear Forbes family:

On behalf of the State of Colorado, I would like to express my sincere appreciation for the environmental protections you have emplaced on Trinchera Ranch for our future generations.

Largely due to your efforts, the Trinchera Ranch now serves as a sanctuary for Colorado wildlife. Numerous game and non-game species, including bighorn sheep, Rio Grande cutthroat trout, and other vital species will continue to thrive on the ranch for years to come. Your devotion to the Colorado community will allow generation upon generation to experience our state animal and other magnificent species. The philanthropic value of your family's contributions are second to none, and it is with great pleasure that I convey my thanks for all you have done for our state's wildlife. You have helped create one of Colorado's most valuable environmental assets.

Your family's leadership in preserving our state's heritage can only inspire others to do the same. Thank you once again for your efforts, and congratulations on the ranch's soaring success.

Sincerely,

Bill Ritter, Jr.

Bill Ritter, Jr.
Governor

07A-447E

Fyl

c·3

cc

(1)

E

(1)

Xcel Energy

2009 FEB 10 PM 4:35

An Effective Load Carrying Capability Analysis
for Estimating the Capacity Value
of Solar Generation Resources
on the Public Service Company of Colorado System

By Xcel Energy Services, Inc.
February 2009

Table of Contents

Table of Tables

Table of Figures and Charts

The following report describes the analysis Xcel Energy performed to determine the effective load carrying capability, ELCC, of solar resources on the Public Service Company of Colorado ("Public Service") system. The results provided are based on a set of assumptions and solar generation scenarios as described in this report.

Background

In the 2007 Colorado Resource Plan,[1] Xcel Energy committed to provide the Colorado Public Utilities Commission with an analysis of the capacity credit to be afforded solar resources located in Colorado in the Phase II evaluation of bids. Xcel Energy completed a similar analysis evaluating the Effective Load Carrying Capacity (ELCC) for wind resources in March, 2007.

Executive Summary

Public Service ("Company") strives to provide reliable electric service at all times to its customers. As a result, the Company works to maintain an adequate supply of electric generation capacity that will meet the expected maximum demand of its customers (i.e., the "peak" demand) under a range of circumstances. When the reserve margin (the amount of excess generating capacity above peak demand) is projected to fall below a desired amount, Public Service will acquire additional electric generating capacity or demand reduction programs to bring the reserve margin back to the desirable level. As Public Service pursues additional solar generation for its system, the capacity value ascribed to these solar resources will play an increasingly important role in this process.

This report discusses the methodology and results of a study performed by Public Service to quantify the capacity value of solar resources on the Public Service system based on the effective load carrying capability ("ELCC") calculated for these solar resources. The calculation of ELCC incorporates use of probabilistic measures of electric system reliability termed loss of load probability ("LOLP") and loss of load expectation ("LOLE") to quantify the reliability contribution that solar resources provide to the electric system. The annual sum of hourly system LOLP values results in the LOLE probabilistic measure. By comparing the annual system LOLE that results from adding solar generation to that resulting from the addition of a traditional, dispatchable gas-fired thermal unit, Public Service was able to estimate an ELCC value of solar resources.

The resulting solar resource ELCC values calculated from this study varied depending on solar technology and location within the state. Three technologies were studied (fixed panel photovoltaic ("PV"), single-axis tracking PV, and solar thermal parabolic trough) in three locations within the state (Denver, Pueblo, and Alamosa). Looking across technologies, the average capacity valuation for solar

[1] Commission Docket No. 07A-447E

resources ranged from 59 percent to 81 percent of nameplate (i.e., a 100 MW nameplate solar facility would get 59 MW to 81 MW of generation capacity credit). The lowest capacity credit values calculated were for fixed panel PV applications while solar thermal trough and single-axis tracking PV facilities exhibited the highest capacity credit values. Solar thermal facilities with thermal storage were not examined in this study since such facilities should be capable of providing full nameplate capacity (i.e., 100% capacity credit) during the system peak hours if they are designed with sufficient levels of storage capability. Solar generators located in Denver and Alamosa had similar capacity values while Pueblo showed the highest capacity values of the three locations studied.

Section 1: Introduction

The role of renewable generation resources has gained prominence in the utility industry for environmental and fuel saving benefits. With volatility in natural gas prices, potential taxes on carbon emissions, and a 30% federal investment tax credit for solar projects, the relative economics of solar generation are becoming more competitive with traditional thermal units on a dollar per megawatt hour basis. This increased competitiveness along with the Company's environmental leadership strategy has led Public Service to consider adding significant amounts of solar generation to its electric supply portfolio. Therefore, it is increasingly important for the Company to understand the operational characteristics of solar technologies and how to consider the different solar technologies in the generation capacity and reliability planning process. To further this understanding, Public Service agreed to analyze the capacity value of solar generation and has, in this study, employed the ELCC approach to do so. ELCC was previously used in the Company's analysis of the capacity credit value of wind resources that was filed with the Colorado Public Utilities Commission in March 2007.

This study was performed to determine the capacity credit value of solar resources, that is, the ability of a facility or facilities converting sunlight to electricity to reliably meet customer load. It was not performed to determine the annual energy capacity factor of solar generators, that is, the total MWh of electrical energy generated in a year relative to the maximum number of MWh that could be generated if the generator operated at maximum nameplate capacity every hour of the year.

Xcel Energy's prior ELCC study of wind generators found that the capacity value of those facilities was significantly less than their annual energy capacity factor owing to the relatively poor correlation between wind generation in the Colorado region and Public Service system peak load hours. In this study however, it was anticipated that the capacity value of solar generation in the Colorado region would significantly exceed the annual energy capacity factor of such resources given the better correlation between the solar resource and system peak load hours, as prior studies have indicated.[23]

[2] "Update: Effective Load-Carrying Capability of Photovoltaics in the United States", Perez, Margolis, Kmiecik, Schwab, Perez; NREL/CP-620-40068; June 2006 (www.nrel.gov/pv/pdfs/40068.pdf)

Section 2: Use of Loss of Load Expectation for Resource Capacity Valuation

The calculation of ELCC incorporates use of probabilistic measures of electric system reliability termed loss of load probability ("LOLP") and loss of load expectation ("LOLE") to quantify the reliability contribution that solar resources provide to the electric system. The annual sum of hourly system LOLP values results in the LOLE probabilistic measure. By comparing the annual system LOLE that results from adding solar generation to that resulting from the addition of a traditional, dispatchable gas-fired thermal unit, Public Service was able to estimate an ELCC value of solar resources.

LOLE is a probabilistic measure of an electric system's ability to maintain service to firm customer load. LOLE represents the expectation of the power system having insufficient generation supplies to serve customer load requirements. The annual LOLE for the Public Service system is calculated by summing hourly LOLP values that are derived from computer modeling of the Company's electric supply system. An electric system with a probability of being unable to serve customer load requirements one day every ten years would have an LOLE equivalent to 2.7397 X 10^{-4} which is derived by dividing 1 day by 3650 days (365 days per year times 10 years, leap years excluded). An LOLE equivalent to 2.7397 X 10^{-4} can be simply described by dividing 24 hours by the number of hours in ten years, or 2.4 hours divided by 8760 hours per year. This report generally refers to LOLP when discussing reliability on an hourly basis and LOLE when describing reliability on an annual basis. LOLE for the Public Service system will vary from year to year depending on the number of generators installed on the system, the maintenance requirements of those generators, the potential unavailability of generation, the total megawatts of generation available on the system, and characteristics of the system load requirements. Higher LOLE values result from a combination of low system operating reserve margins and high load requirements. Under these circumstances there is a higher expectation that the system will have insufficient generation capacity (once forced outages are considered) to serve load. Alternatively, when larger operating reserve margins exist and load is low, the expectation of not being able to serve load is low and LOLE values diminish.

Electric generator availability was represented in the LOLE calculations by two types of outages: unplanned and planned. Unplanned outages are represented by the expected forced outage rate ("EFOR") of the individual generators; these forced outages typically occur randomly. Planned outages represent maintenance outages that the utility schedules and therefore has some control over their occurrence. In this study, maintenance outages were either represented using actual maintenance outage schedules (i.e., the specific days for which outages are scheduled to occur) or an estimate of the number or weeks per year needed for maintenance (i.e., a maintenance rate).

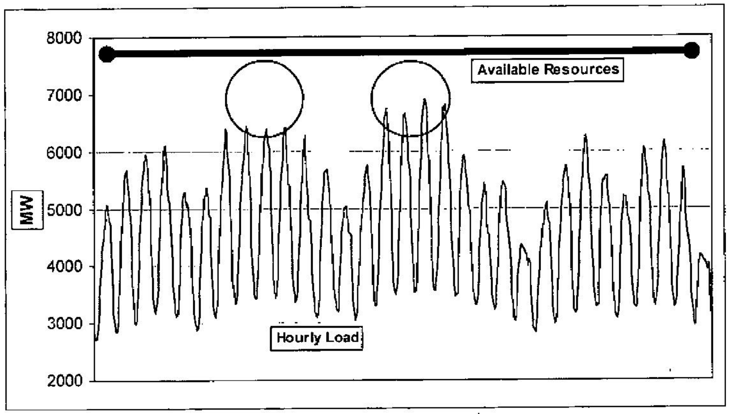
---

[3] "Photovoltaic Capacity Valuation Methods", Hoff, Perez, Ross, Taylor; SEPA Report #02-08; May 2008 (http://www.solarelectricpower.org/docs/PV%20CAPACITY%20REPORT.pdf).

Key Drivers of LOLP/LOLE

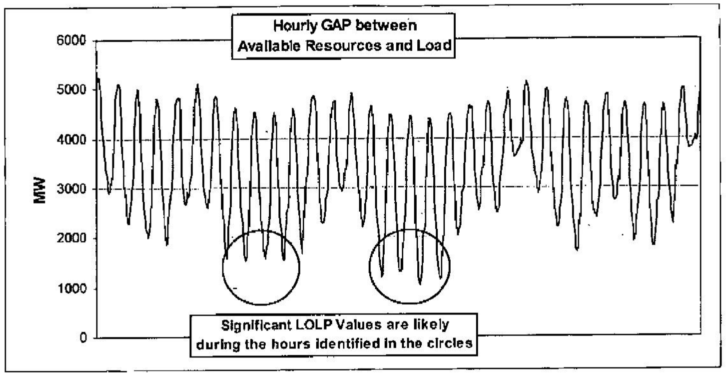
The amount of generation capacity available to a system each hour relative to the system load requirements that same hour has a significant influence on the LOLP/LOLE of the system. Figure 1 provides a graphical representation of the difference between available generation and load over a month for a fictitious electric system. The areas identified in circles show periods where the gap between available generation and load are relatively small. As this gap decreases and the relative magnitude of load increases, LOLP increases.

Figure 1: Resources versus Load



An alternative representation of the difference between available generation and load is shown in Figure 2. As can be seen in the figure, several segments are near the 1000 MW reserve level and are hours where LOLP values may be significant.

Figure 2: Hourly Resources less Hourly Load (GAP)



Section 3: Modeling Assumptions and Methods

The general study methodology was to utilize a computer model[4] representation of the Public Service system containing the system parameters required for LOLP calculation (e.g. generators, EFORs, load, etc) to determine ELCC values for solar resources and compare those with ELCC values for thermal resources.

The data, assumptions, scenarios, and modeling method are developed further below.

Required Data

Data collected for this analysis included:

- Hourly solar energy production estimates for fixed PV, single-axis tracking PV, and solar thermal trough without storage for historical years 2004 and 2005 and for three Colorado location; Alamosa, Pueblo and Denver,
- Historical, hourly Public Service loads for 2004 and 2005,
- Planned and expected maintenance for the portfolio of generation resources in the years 2013-2015,

Hourly solar energy production estimates for the various solar technologies were generated using the National Renewable Energy Laboratory's Solar Advisor Model ("SAM")[5] employing historical, hourly meteorological data (e.g., solar irradiance and

[4] Ventyx's ProSym software.
[5] https://www.nrel.gov/analysis/sam/

air temperature) for the three examined locations from the Perez satellite data set.[6] In order to reduce the total number of cases examined but still capture the effects of the various cell technologies mounted in various orientations and interconnected to the Public Service system, the hourly energy production profiles employed in the study were generated from multiple SAM model runs and then averaged. Energy production profiles for the fixed PV cases were an average of profiles generated by the SAM model from polycrystalline silicon and thin-film CdTe modules with orientations facing due south and 20 degrees west of south; single-axis tracking PV cases were an average of profiles generated by the SAM model for polycrystalline silicon modules mounted in tracking systems in both horizontal and latitude-tilt orientations.

Higher capacity values for fixed (i.e., non-tracking) PV facilities can be obtained by orienting the panels to face west of south in order to capture more direct sunlight later in the afternoon during typical peak load hours. However, this orientation results in lower annual energy capacity factors. A detailed analysis would need to be conducted to determine if higher capacity values are sufficient to cover the overall higher solar energy prices (caused by the reduction in electricity generation) that results from an orientation other than due south. This study did not attempt to determine the optimum, west-of-south position that would maximize the relative value of increased capacity versus the cost of decreased electrical output.

This study also did not attempt to determine the impact that sub-hourly variations in PV generation (intermittency) might have on that technology's capacity valuations; a discussion of these potential impacts is presented in the SEPA Report #02-08. [3]

Modeling Assumptions

In addition to the model input data listed above, certain key assumptions were used in this analysis.

- Public Service's system reliability measure was set to an annual LOLE of 1 day in 10 years, [7] (2.7397×10^{-4}),
- Public Service loads for the years 2013-2015 were generated within the ProSym model based on historical 2004 and 2005 loads,
- 2013-2015 load shapes generated from 2004 load were matched with solar generation profiles based on 2004 meteorological data and 2013-2015 load shapes generated from 2005 load were matched with solar generation profiles based on 2005 meteorological data,
- PV cases were assessed a three (3) percent unavailability rate within the ProSym model which is a rate similar to PV system unavailability in NREL's PV Watts model,

[6] https://rpm.nrel.gov/

[7] A study conducted in 2008 by Ventyx provides the basis for the PSCo system reserve margin. The study determined that an appropriate reserve margin for PSCo is 16%. For this study, a LOLE of one day in ten years, a traditional industry value, 2.7397 X 10-4 = 1day / (365 days X 10 years) was used.

* Parabolic trough cases were assessed a six (6) percent unavailability rate within the ProSym model based on the unavailability rates provided in the generic parabolic trough cases provided with the SAM model,

Solar Scenarios Modeled

Three solar technologies were examined in the study: fixed PV, single-axis tracking PV, and solar thermal trough without storage. For each of these three technology scenarios the study considered three possible Colorado locations; Denver, Pueblo, and Alamosa. Three separate technologies and three separate locations resulted in nine (9) independent scenarios per analytical year; an analytical year is the historical year from which the load and solar pattern data is developed. For this study, historical 2004 and 2005 data were used to develop two sets of hourly load and solar data. Considering two analytical years doubles the nine modeled scenarios for a total of eighteen (18) scenarios.

Capacity values were calculated at a single level of installed solar (100 MW nameplate). This level of solar on the Public Service system in the 2013-2015 time frame studied represents a penetration level of approximately 1.4% based on peak demand. As shown in the SEPA #02-08 report, the capacity value attributed to solar generation at higher penetration rates decreases from values calculated at lower penetration rates.

Modeling Method

Base LOLE model runs of the Public Service system for years 2013-2015 were performed prior to the addition of the solar facilities identified in Table 1. An iterative process was applied to get these base runs set to a LOLE of one day in ten years by either increasing or decreasing load, as needed, equally over all hours of the year. This process of shifting the hourly load retains the hourly load shape while setting the base models' starting LOLE to one day in ten years.

Next, for each of the eighteen scenarios, a 100 MW solar facility was added to the system resource mix. The addition of this 100 MW resource acted to increase the overall system reliability (and thus reduce the system LOLE). For example, the addition of 100 MW of fixed PV in Denver was added to the system resource mix resulting in an increase in system reliability from 1 day in 10 years to 1 day in 14 years.

Next, the solar facility was removed from the model and a single dispatchable thermal unit was added in 5 MW increments from 45 MW up to 250 MW resulting in forty-two (42) separate model runs per scenario year.

The LOLE values from these forty-two thermal unit model runs were put into a matrix of LOLE values at 5 MW increments. A sample of the thermal unit matrix is shown in Table 2.

Table 1: Thermal Unit LOLE Matrix

CT Capacity	2013	2014	2015
45	2.005E-04	2.022E-04	2.029E-04
50	1.936E-04	1.954E-04	1.960E-04
55	1.871E-04	1.888E-04	1.895E-04
60	1.807E-04	1.826E-04	1.832E-04
65	1.745E-04	1.766E-04	1.772E-04
70	1.687E-04	1.709E-04	1.714E-04
75	1.631E-04	1.651E-04	1.660E-04
80	1.576E-04	1.596E-04	1.604E-04
85	1.523E-04	1.544E-04	1.550E-04
90	1.472E-04	1.493E-04	1.500E-04
95	1.423E-04	1.443E-04	1.450E-04
100	1.374E-04	1.398E-04	1.403E-04

The 100 MW solar LOLE values were then compared to those in the thermal unit LOLE matrix to obtain a corresponding thermal unit capacity equivalence value. The corresponding thermal unit capacity was divided by the nameplate capacity of the solar scenario to estimate the percentage annual capacity credit value, or ELCC. An exact solar LOLE to thermal unit LOLE match rarely occurs, however by bounding the solar LOLE value between two successive 5 MW increments in the Thermal Unit LOLE matrix, linear interpolation can be used to obtain a reasonably accurate estimate of LOLE.

Continuing the example from above, the 100 MW solar LOLE annual values were 1.9020E-04, 1.8841E-04, and 1.9257E-04 for years 2013-2015 respectively. Looking up and interpolating in the Thermal Unit Matrix for each year's LOLE results in equivalent thermal unit capacity of 52.6 MW, 55.3 MW, and 52.7 MW respectively. For this scenario, the average of these thermal-unit capacities versus the 100 MW nameplate solar facility results in an average capacity value of 53.5%.

Section 4: Analysis Results

Table 2 presents the solar capacity credit calculated in this study in terms of thermal-unit equivalent percentages by modeled year.

Table 2: Solar – Thermal Unit Equivalent Capacity Values

	2004 Pattern Year			2005 Pattern Year			2004 / 2005 Averges		
Location	Fixed PV	1-Axis PV	Trough	Fixed PV	1-Axis PV	Trough	Fixed PV	1-Axis PV	Trough
Denver	53.5%	69.5%	69.7%	63.6%	68.0%	70.7%	59%	69%	70%
Pueblo	55.7%	74.2%	79.5%	69.8%	76.3%	83.3%	63%	75%	81%
Alamosa	53.4%	66.8%	65.7%	66.4%	70.7%	71.2%	60%	69%	68%

Examination of the results shows several relevant findings:

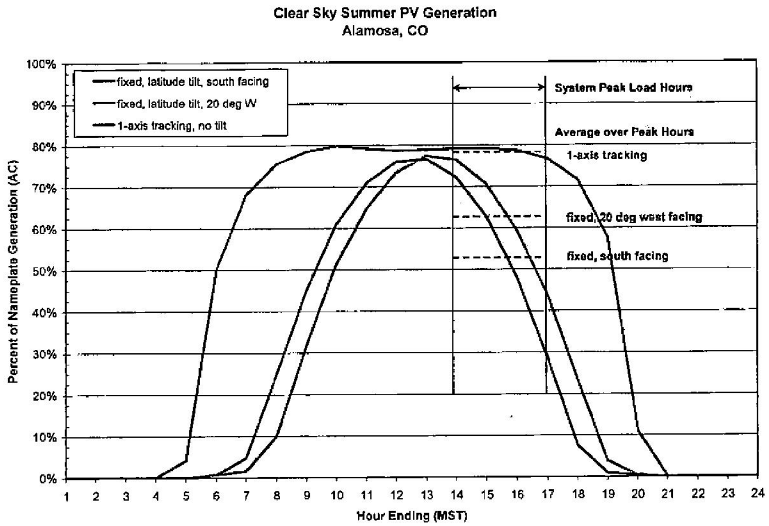
- As expected, single-axis tracking PV and solar thermal trough technologies exhibit higher capacity values than fixed PV.
- Capacity values calculated using 2004 historical load and meteorological data are lower than those values using 2005 historical data; capacity values for the fixed PV cases were markedly lower.
- Capacity values across all technology types for solar facilities located in Pueblo were higher than for Denver or Alamosa.

2004 Results vs. 2005 Results

The most likely explanation for the higher capacity value calculations from the 2005 historical data sets is that in 2005, system peak load hours (or alternatively, those hours resulting in the largest levels of LOLP) occurred earlier in the day than in 2004. The effect of system peak load occurring earlier in the day on LOLP can be illustrated with Figure 3.

Figure 3 shows the hourly generation on a clear-sky day in Alamosa from identically sized, single-axis tracking PV and fixed PV facing due south and 20 degrees west of south solar facilities. Figure 3 also indicates the typical summer peak system load hours (HE 14 – 17, MST). Generation for the south-facing, fixed PV facility drops from 72% of nameplate during HE 14 to 29% of nameplate during HE 17; generation from the fixed PV facing west of south drops from 77% of nameplate during HE 14 to 44% of nameplate during HE 17 (illustrating the capacity value benefits of positioning fixed PV in a west of south orientation); generation from the single-axis tracking PV system drops from 79% to 77% in the same period. The pattern of large changes from the 2004 load shapes to the 2005 load shapes for fixed PV matches the effects shown in Table 2 if the high LOLP hours occur earlier in the day for the 2005 load shapes.

Figure 3 Clear Sky, Summer PV Generation in Alamosa, CO



Given the variation noted between 2004 and 2005 load shapes in the final result, future studies may need to evaluate data from more than two years. Currently, studies are limited by historical meteorological data in that 2005 is the most recent year for which data are available.

Capacity Value Results by Location

As previously indicated, capacity values for facilities located in Pueblo were consistently higher than for Denver or Alamosa. An examination of hourly weather conditions in both 2004 and 2005 indicate a significantly higher correlation of peak system load hours with clear skies in Pueblo than with clear skies in Alamosa. That is, the chances of afternoon, monsoon conditions in Alamosa during Public Service peak load conditions appear to be greater than such conditions occurring in Pueblo. Thus, even though the annual energy capacity factor from a solar facility located in Alamosa is higher than the same plant located in Pueblo; generation from the Pueblo plant is better correlated to Public Service's peak loads.

SunE Alamosa Generation during 2008 Peak Load Hours

SunEdison operates an 8.2 MW (dc) PV facility north of Alamosa in the San Luis Valley. The facility is primarily constructed of single-axis trackers (no tilt) with smaller portions constructed of both two-axis tracking modules and south-facing fixed modules (with tilt angles manually repositioned on a seasonal basis). Thus, it would be expected that the capacity value of generation from this facility would be approximately 65-70% based on the data shown in Table 2.

An analysis of SCADA-quality, hourly average generation data from the SunEdison facility for the 2008 summer generation period was conducted to estimate the capacity value. The average generation from the facility over the top 50 load hours during 2008 was found to be 70% of the AC nameplate.

Section 5: Summary

Xcel Energy believes that this analysis provides a good foundation for determining the reliability contribution that solar resources are likely to provide to the Public Service system. Based on the analyses performed to date and discussed in this report, average capacity values ascribed to solar generators for the Company's Phase II evaluations are:

- for facilities near Denver: 59% for fixed panel PV, 69% for single-axis PV, and 70% for trough facilities,
- for facilities near Pueblo: 63% for fixed panel PV, 75% for single-axis PV, and 81% for troughs,
- and for facilities near Alamosa: 60% for fixed PV, 69% for single-axis PV, and 68% for troughs.

PUBLIC SERVICE COMPANY OF COLORADO

2009 All Source Solicitation

Request for Proposals
For
Semi-Dispatchable Renewable Capacity Resources

Xcel Energy

January 2009

Table of Contents
Public Service Company of Colorado
2009 Semi-Dispatchable Renewable Capacity Resources RFP

Appendices

Appendix A
Proposal Forms and Instructions

Appendix B
General Planning Assumptions

Appendix C
Transmission Costs and Energy Resource Zones ("ERZs")

Appendix D
Model Power Purchase Agreement

Index of Appendix A Forms

Form A	Notice of Intent to Respond
Form B	Bid Certification
Form C	Bid Cover Sheet
Form D	Pricing
Form E	Construction Milestones
Form F	Delivery Arrangements
Form G	Large Generator Interconnection Request
Form H	Representation Authorization
Form I	Technical Descriptions
Form J	Emission Rates
Form K	Energy Production Profiles
Form L	Natural Gas Supply

Notice of Disclaimer

The information contained in this Request for Proposals ("RFP") for generation and/or capacity resources has been prepared solely to assist respondents in deciding whether or not to submit a proposal. Public Service Company of Colorado ("Public Service" or "Company") does not represent this information to be comprehensive or to contain all of the information that a respondent may need to consider in order to submit a proposal. None of the Company, its affiliates, or their respective employees, directors, officers, customers, agents and consultants makes, or will be deemed to have made, any current or future representation, promise or warranty, express or implied, as to the accuracy, reliability or completeness of the information contained herein, or in any document or information made available to a respondent, whether or not the aforementioned parties knew or should have known of any errors or omissions, or were responsible for their inclusion in, or omission from, this RFP.

The Company reserves the right to modify, supplement or withdraw this RFP at any time, whether due to changes in law or otherwise, and including by issuing one or more addenda to this RFP during this solicitation, which addenda shall become a part of this RFP. No part of this RFP and no part of any subsequent correspondence by the Company, its affiliates, or their respective employees, directors, officers, customers, agents or consultants shall be taken as providing legal, financial or other advice or as establishing a contract or contractual obligation. Contractual obligations on the part of the Company will arise only if and when definitive agreements have been approved and executed by the appropriate parties having the authority to approve and enter into such agreements. The Company reserves the right to request from a respondent (a.k.a., bidder) information that is not explicitly detailed in this document, obtain clarification from respondents concerning proposals, conduct contract development discussions with selected respondents, conduct discussions with members of the evaluation team and other support resources as described in this RFP and in compliance with all Federal Energy Regulatory Commission ("FERC") Code of Conduct rules and provide data to and conduct discussions with the Independent Evaluator ("IE") as necessary for the IE to satisfy its obligations to the Colorado Public Utilities Commission ("CPUC" or "Commission").

The Company will, in its sole discretion and without limitation, evaluate proposals and proceed in the manner the Company deems appropriate, which may include deviation from the Company's expected evaluation process, the waiver of any requirements and the request for additional information. The Company reserves the right to reject any, all or portions of any proposal received for failure to meet any criteria set forth in this RFP or otherwise and to accept proposals other than the lowest cost proposal. The Company also may decline to enter into any agreement with any respondent, terminate negotiations with any respondent or abandon the RFP process in its entirety at any time, for any reason and without notice thereof. Respondents that submit proposals agree to do so without legal recourse against the Company, its affiliates, or their respective employees, directors, officers, customers, agents or consultants for rejection of their proposals or for failure to execute an agreement for any reason. The Company and its affiliates shall not be liable to any respondent or other party in law or equity for any reason whatsoever for any acts or omissions arising out of or in connection with this RFP. By submitting its proposal, each respondent waives any right to challenge any valuation by the Company of its proposal or any determination of the Company to select or reject its proposal. Each respondent, in submitting its proposal, irrevocably agrees and acknowledges that it is making its proposal subject to and in agreement with the terms of this RFP.

Each respondent shall be liable for all of its costs incurred to prepare, submit, respond or negotiate its proposal and any resulting agreement and for any other activity related thereto, and the Company shall not be responsible for any of the respondent's costs.

Public Service Company of Colorado
2009 RFP for
Semi-Dispatchable Renewable Capacity Resources

Section 1. Introduction

Public Service Company of Colorado, an operating company subsidiary of Xcel Energy Inc., is issuing this Request for Proposals as a component of Public Service's 2009 All-Source solicitation. This particular RFP is one of four RFP's to be issued simultaneously. These four RFP's are:

- 2009 RFP for Wind Resources
- 2009 RFP for Dispatchable Resources
- 2009 RFP for Semi-Dispatchable Renewable Capacity Resources (this RFP)
- 2009 RFP for Non-Wind, Non-Dispatchable Resources

Segmenting the All Source solicitation into these four categories is driven by the power purchase contracting requirements for different generation technologies. As a result, each RFP contains a model contract that has been tailored to address certain issues associated with the operation of each technology.

Examples of the types of projects that are eligible to bid into each RFP are shown in Table 1 below. This list is intended to provide guidance as respondents develop their proposals. Respondents who are uncertain as to which RFP would apply to their specific project should contact the RFP Project Manager (Section 4.6) for clarification.

Table 1. Example Resource Types for the Various RFPs

RFP Document	Resource Types
2009 RFP for Wind Resources	• Wind generators
2009 RFP for Dispatchable Resources	• Simple cycle gas turbines • Combined cycle gas turbines • Pumped storage hydroelectric
2009 RFP for Semi-Dispatchable Renewable Capacity Resources	• Solar thermal with thermal storage or fuel backup • Any other intermittent resource with storage or fuel backup
2009 RFP for Non-Wind, Non-Dispatchable Resources	• Solar without storage or fuel backup • Hydroelectric • Geothermal • Biomass • Recycled energy

The Company invites proposals from all potential suppliers who are capable of meeting the conditions of the 2009 All-Source RFPs.

The Company is also interested in pursuing proposals for Company ownership of generation resources. The Company encourages potential respondents who are interested in offering projects for Company ownership to contact the Xcel Energy Business Development Team (see contact information below) to discuss such opportunities further. Company-developed and owned projects may also be evaluated in parallel with the All-Source solicitation as part of the Commission approved process but bidders to this RFP should not propose Company-owned or joint venture projects as a response to this RFP, but instead should contact the following person well in advance of the RFP due date to discuss such potential arrangements.

Mr. Paras Shah
Director, Business Development
Xcel Energy Inc.
414 Nicollet Mall, 7th Floor
Minneapolis, MN 55401
PSCoSemiDispatchable@xcelenergy.com

The Public Service 2009 All-Source RFP webpage can be found at www.xcelenergy.com (Select Top Menu item "*Company*" then select Left Menu item "*About Energy and Rates*" then select Left Menu item "*Energy RFPs*" and the link for the 2009 PSCo All-Source RFP).

1.1 Regulatory Context

The CPUC's Resource Planning Rules ("RP Rules") establish a process that jurisdictional electric utilities must follow to determine the need for additional electric resources and to procure needed resources. Public Service filed its 2007 Colorado Resource Plan ("CRP") on November 15, 2007 in accordance with the RP Rules. In its 2007 CRP, Public Service identified a resource need and identified a set of resources that, in conjunction with its current portfolio of resources, produces a cost-effective resource portfolio taking into consideration projected system needs, reliability of proposed resources, various risk factors, reduction in carbon emissions, and various CPUC decisions.

An Independent Evaluator (IE) will be involved with the evaluation of proposals received in response to the All-Source solicitation in accordance with Commission RP Rule 3610. In general, the IE will be performing an independent analysis of proposals during the same 120-day period over which the Company will evaluate proposals. At the end of the 120-day period, both the Company and the IE will submit separate reports to the Commission regarding the results of their analyses. Upon receipt of these reports, the Commission will have 90 days (referred to as "Phase II") to complete its evaluation and issue a decision. The Company will work cooperatively with the independent evaluator and shall provide the independent evaluator immediate and continuing access to all documents and data reviewed, used, or produced by the utility in this All-Source solicitation and evaluation process.

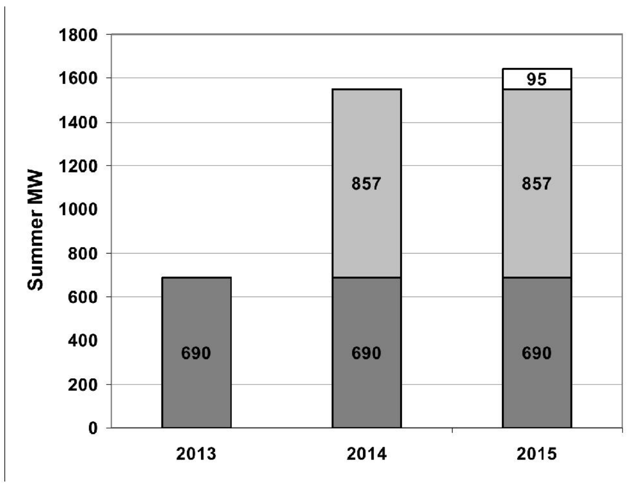
The CPUC heard argument by multiple parties concerning Public Service's resource need and resource acquisition plans and approved Public Service's 2007 CRP with modifications on September 19, 2008. The CPUC approved the issuance of this All-Source solicitation and provided direction regarding the

Phase II process, the solicitation, evaluation of bids and Company-owned proposals, and the role of the IE in Decisions No. C08-0929, C08-1153, C08-1337 and C09-0004.

1.2 Resource Needs Assessment

This RFP is part of an All-Source solicitation process whose purpose is to acquire sufficient generation supply resources to meet the Company's forecasted electric demand (plus reserves) over the 8-year resource acquisition period ("RAP") of 2008-2015 as well as acquire resources that will enable the Company to achieve reductions in carbon emissions. The Company estimates it will need to acquire approximately 1,600 MW of generation capacity[1] over the RAP[2] to meet summer peak load[3] plus a 16% planning reserve. Figure 1 illustrates the general timing of this capacity need by year.

Figure 1. Estimated Generation Capacity Needs by Year



In any year, the Company may acquire more or less generation capacity than is shown in Figure 1 and the final level of resource need by year may change from

[1] The 1,600 MW refers to generation capacity that the Company would rely upon to meet customer demand during peak load conditions plus reserves. Certain generation resources such as wind and photovoltaic solar will count towards this 1,600 MW at a level less than the nameplate rating of the facility. As a result the final resource mix selected through the All-Source solicitation could include significantly more than 1,600 MW from a nameplate rating standpoint.

[2] The ultimate resource need and/or components of that need may differ as a result of adjustments to reflect any subsequent forecast updates or other events that would impact the identified resource need during the RAP, including decisions of the CPUC.

[3] Assuming a level of DSM reflected by 100% of the CPUC Goals

that in Figure 1 due to changed circumstances. While Figure 1 shows an estimated capacity need only for years 2013-2015, the Company is also seeking resources through the All-Source solicitation that become commercially operational prior to 2013 (e.g., wind generation).

The following limitations apply in selecting resources in this All-Source solicitation:

- Public Service established a target acquisition of 850[4] MW of intermittent resources to be acquired in targeted increments of 100 to 200 MW a year.
- Public Service plans to acquire a minimum of 200 MW of solar thermal with storage subject to CPUC review[5].
- Public Service established a target acquisition of 600 MW of concentrating solar thermal with either thermal storage or fuel backup to be acquired in targeted increments of roughly 200 MW per year.

1.3 Resources Sought through this RFP

Through this Semi-Dispatchable Renewable Capacity Resources RFP, the Company seeks proposals from facilities that utilize intermittent eligible energy resources and employ an integral, supplemental technology that serves to lessen the intermittency effects of the energy source. The supplemental technology may allow energy production to be shifted to hours of greater value to the Company and/or may provide generation capacity to the system during peak load periods at a level significantly closer to the nameplate rating of the facility. Examples of eligible technologies include solar with storage or solar thermal with fuel backup/hybridization. All resources offered through this RFP must achieve commercial operation no later than May 31, 2015.

The amount of generation that the Company may acquire from this Semi-Dispatchable Renewable Capacity Resources RFP depends, among other things, on the quality of bids received in response to the All-Source solicitation, economic comparison to other RFP responses and Company proposals, on updates to the Company's forecasts, on regional transmission availability, and on changes to regulatory or legal requirements.

[4] This 850 MW includes a combined amount of intermittent generation resources but does not include the amounts projected to be acquired under the Solar*Rewards program. The allocation between wind, solar, and other intermittent resources will be based on the results of the All-Source evaluation. This 850 MW includes any amounts obtained and approved by the Commission as part of the Company's early wind activities, the 2008 PSCo Solar Resource RFP, and this All-Source solicitation process. The amount of generation capacity equivalent represented by this 850 MW will depend on the final types of intermittent resources selected in the All Source solicitation process.

[5] In Decision C08-0929, the CPUC wrote: "We grant Public Service's request for a set-aside of 200 MW of solar with storage. We grant this 200 MW set-aside on the assumption that reasonable bids will be received, and that Public Service reserves the right to reject all such bids if the Commission determines that the Section 123 bids or proposed utility facilities do not represent the developmental technology contemplated in C.R.S. 40-2-123, or is otherwise significantly out of line in the market for current technology."

1.4 Section 123 Resources

Colorado Revised Statutes ("C.R.S.") 40-2-123(1)(a) states:

> "The commission shall give the fullest possible consideration to the cost-effective implementation of new clean energy and energy-efficient technologies in its consideration of generation acquisitions for electric utilities, bearing in mind the beneficial contributions such technologies make to Colorado's energy security, economic prosperity, environmental protection, and insulation from fuel price increases."

These "new clean energy and energy-efficient technologies" are referred to as Section 123 resources. In Decision No. C08-559, the CPUC found that the acquisition of Section 123 resources that are also eligible energy resources (as those resources are defined in C.R.S 40-2-124(1)(a)) are not subject to the retail rate impact rule of C.R.S. 40-2-124(1)(g).

The Commission clarified in Decision No. C08-1153 that the Western Resource Advocates' definition of Section 123 resources is the definition of Section 123 adopted by the Commission. That definition is as follows:

> "…an eligible energy resource will be considered a new clean energy, or energy efficient technology, or a demonstration project if it is clean and incorporates one or more technologies, representing a substantial portion of its overall installed cost, that have not been regularly commercially demonstrated, up to the point in time the resource is formally bid, or if not bid, acquired."[6]

In Decision No. C08-0929, the CPUC established that concentrating solar power with storage and wind with compressed air storage are Section 123 resources. In that decision, the Commission also established the following definition of Section 123 resources:

- "An eligible energy resource will be considered a new clean energy, or energy efficient technology, or a demonstration project if it is clean and incorporates one or more technologies, representing a substantial portion of its overall installed cost, that have not been regularly commercially demonstrated, up to the point in time that the resource is formally bid, or if not bid, acquired."

Respondents to this RFP who propose a resource that they believe meets the definition of a Section 123 resource should indicate in their proposal why the respondent believes the resource qualifies as a Section 123 resource. Public Service and the IE shall each review claims for Section 123 qualification. Should there be a dispute between the Company and the IE as to whether a proposed resource qualifies as a Section 123 resource, the Company and the IE will request a CPUC ruling to decide this issue.

---

[6] Supplemental Answer Testimony of Michael B. Mendelsohn, June 9, 2008, Page 2, Lines 14-18.

Section 2. Eligible Project Information

2.1 Eligible Project Structures

All RFP proposals must be for purchase of energy by the Company under a power purchase agreement ("PPA") subject to the accounting considerations discussed in later sections of this RFP. The Model PPA[7] is provided in Appendix D.

Respondents interested in developing proposals that involve Company ownership of generating facilities should contact the Xcel Energy Business Development Team as soon as possible as discussed in Section 1. The Company may submit Company proposals in competition with PPA proposals.

2.2 Eligible Generation Resources

Intermittent generation resources, e.g. solar, with storage or fuel backup can bid into this RFP. Respondents are encouraged to review Section 3 and Appendix C for a discussion of the economic benefits of locating proposed projects in designated Energy Resource Zones ("ERZs").

As discussed in Section 2.5, all proposals must include the transfer to the Company of 100% of the environmental benefits and renewable energy credits ("RECs") associated with the energy generated by the project and purchased by the Company.

Projects of 30 MW or less in size are not eligible to bid under this RFP or any of the other RFPs comprising the All-Source solicitation. The Company proposes to evaluate resources of 30 MW or less in size outside of the All-Source solicitation on a case-by-case basis.

2.3 Pricing

Form D contains the pricing templates for PPA proposals. All pricing must be in terms of current year dollars, also referred to as escalated or nominal dollars. For example, a $100 per megawatt-hour ("MWh") energy price bid for year 2019 means that in 2019, energy from the facility will be purchased at a base rate of $100/MWh. All proposals submitted into the Company's All-Source solicitation for non-wind generation resources must propose a fixed price for the first year of the PPA. Energy prices in subsequent years may remain flat, change at a known and specified rate, or change according to a known, published and widely recognized index that is closely related to the appropriate generation segment of the power industry.

To help assure that generation output of the facility will be available during system peak load conditions, the model PPA for the Semi-Dispatchable Renewable Capacity Resources RFP contains hourly payment rates based on the base energy payment rates provided on Form D1 and time-of-day price

[7] The Model PPAs are sample agreements containing terms and conditions acceptable to the Company. The Company understands that respondents may desire to modify and supplement the Model PPA when submitting their proposals, and anticipates negotiating with selected respondents in an effort to develop documents acceptable to both parties.

adjustment factors shown in Exhibit P of the model PPA and in Table 2 below. The price paid during any single hour of generation will be the product of the base energy rate from Form D1 and the relevant time-of-day price adjustment factor.

Projects that propose integrated fuel backup/hybridization may elect to recover the incremental capital costs of the hybridization equipment through either the Form D1 base energy payment rates or, alternatively, through a monthly demand payment rate that respondents should provide on Form D2. In addition, any variable O&M and/or start charges that will be charged to the Company for dispatch of the fuel hybridization component should also be shown on Form D2.

Proposal pricing must include initial cost estimates for any new or upgraded interconnection facilities required for electrical interconnection of the proposed project to the Public Service transmission system, and must include the cost of any dedicated radial transmission line(s) from the generation facility to the proposed point of interconnection. For projects with an active Large Generator Interconnection Procedures ("LGIP") request, the respondent should provide the LGIP identifier(s) associated with the proposed project. Respondents should clearly and separately indicate the estimated cost of electrical interconnection by listing each component of the interconnection facilities as a separate and distinct line item in their proposals.

The Company will pay any costs required to upgrade or reinforce the Public Service electric transmission system beyond the Point of Delivery, as a consequence of adding a respondent's project to the Public Service system. Respondents, however, will be responsible for procuring transmission service and any associated third-party transmission costs needed to deliver power from the project to the Point of Delivery on the Public Service transmission system. All pricing in respondents' proposals should reflect those costs (to the extent applicable) at the time of submittal.

Table 2. Time of Day Price Adjustment Factors

	Summer Peak	Shoulder	Winter Peak
Hour Ending, Mountain Prevailing Time	July, August	March, April, May, June, September, October	January, February, November, December
1	0.50	0.50	0.50
2	0.50	0.50	0.50
3	0.50	0.50	0.50
4	0.50	0.50	0.50
5	0.50	0.50	0.50
6	0.50	0.50	0.50
7	0.50	0.50	1.00
8	1.00	1.00	1.00
9	1.00	1.00	1.00
10	1.00	1.00	1.00
11	1.00	1.00	1.00
12	1.25	1.00	1.00
13	1.25	1.00	1.00
14	1.25	1.00	1.00
15	1.75	1.00	1.00
16	1.75	1.00	1.00
17	1.75	1.00	1.00
18	1.75	1.00	1.25
19	1.25	1.00	1.50
20	1.25	1.00	1.50
21	1.25	1.00	1.25
22	1.00	0.75	0.75
23	1.00	0.75	0.75
24	0.75	0.75	0.75

2.4 Federal Tax Credits

H.R. 1424, The Energy Improvement and Extension Act of 2008, extended the existing 30% Business Energy Tax Credit ("ITC") to include solar energy property placed in service on or before December 31, 2016 and renewed and expanded the Renewable Electricity Production Tax Credit ("PTC") for varying lengths of time for different qualifying energy resource technologies. As the ITC for solar energy property extends past this RFP's 8-year RAP, respondents should price all solar projects assuming they are eligible for a 30% ITC. In contrast, given the uncertainty in future PTC programs at the time this RFP is released and the significant impact such tax credits have on the prices of energy bid to the Company, respondents electing to utilize the PTC must provide pricing both with and without the PTC at their current levels and terms. In the absence of certainty regarding the availability of PTCs during this RFP's RAP, the Company will evaluate bids on the basis of assuming that the PTCs are extended throughout the RAP; however, the Company reserves the right to re-evaluate whether to execute a contract at the non-PTC price should this issue still be uncertain at the time of contract execution.

2.5 Environmental Benefits and Renewable Energy Credits ("RECs")

In Colorado, a Renewable Energy Credit ("REC") results from the production of 1 MWh of energy generated from an eligible energy resource. Under the terms of any transaction (including any PPA), all RECs from a proposed project and the power generated there from will be conveyed to the Company. All environmental benefits associated with the generation will also be conveyed to the Company.

Colorado sited eligible energy resources receive a 1.25 multiplier (MWH produced X 1.25). Public Service will include the REC multiplier in the economic screening of proposals.

2.6 Regulatory Approvals

At the completion of the All-Source bid evaluation process, the Company and the IE will each file a report with the Commission that identifies proposed resource selections as required in RP Rule 3610(h). Upon Commission approval of Phase II of the Company's 2007 Colorado Resource Plan, Company actions consistent with that approval are presumed prudent under RP Rule 3613(d). However, the Company reserves the right to inform the Commission that the Company could not reach agreement with the proponent of a selected resource. The Company further reserves the right to request Commission approval of any agreements it enters into with successful respondents that vary in any material respect from the Model PPA. The Company further reserves the right to terminate any agreement if the Company fails to receive Commission approval of submitted agreements.

2.7 Contract Lengths

Respondents to this RFP shall propose one contract term length for each proposal. Contract term lengths may be between five (5) and twenty-five (25) years. The Company's objectives with respect to term lengths are to avoid the concurrent expiration of multiple contracts and to avoid or minimize the adverse financial impact of imputed debt, capital lease, and Variable Interest Entity-related obligations.

2.8 RoFo and Purchase Option

The Model PPA includes a Right of First Offer ("RoFO") which specifies, in addition to other terms and conditions that the Company may purchase the facility if and when the facility owner is interested in selling the facility to a third party during the term of the PPA. While not required under the Model PPA, respondents, at their option, may offer the Company an end-of-term or other purchase option that specifies that the Company can purchase the facility (or the stock of the facility owner) for its appraised fair market value at a specified time or times during, or at the end of, the PPA term.

2.9 Contract Accounting

All contracts proposed to be entered into as a result of this RFP will be assessed by the Company for appropriate accounting and/or tax treatment. Respondents shall be required to supply promptly to the Company any and all information that the Company requires in order to make such assessments.

The Company has specific concerns regarding proposals received in response to this RFP that could result in either (i) a contract that must be accounted for by the Company as a capital lease or an operating lease[8] pursuant to SFAS No. 13, or (ii) consolidation of the seller or assets owned by the seller onto the Company's balance sheet due to Variable Interest Entity[9] ("VIE") issues. The following shall therefore apply to any proposal submitted pursuant to this RFP:

- The Company is unwilling to be subject to any accounting or tax treatment that results from a PPA's capital lease or FIN 46 treatment. As a result, respondents shall state in their proposal(s) (i) that the respondent has considered applicable accounting standards in regard to capital leases and variable interest entities, i.e., FASB Statement No. 13, Accounting for Leases**,** FASB Interpretation No. 46(R), Consolidation of Variable Interest Entities and Emerging Issues Task Force issue No. 01-08, Determining Whether an Arrangement Contains a Lease, (ii) summarize any changes that the respondent proposes to the Model PPA in order to attempt to address these issues, and (iii) to the respondent's knowledge and belief, the respondent's proposal should not result in such treatment as of the date of the proposal.

- As applicable, the Company will not execute a PPA without confirmation from the Company's external auditors that the PPA will not be classified as either a capital lease or a VIE.

[8] "Capital Lease" and "Operating Lease" – shall have the meaning as set forth in the Statement of Financial Accounting Standards ("SFAS") No. 13 as issued and amended from time to time by the Financial Accounting Standards Board.
[9] "Variable Interest Entity" or "VIE" – shall have the meaning as set forth in Financial Accounting Standards Board ("FASB") Interpretation No. 46 (Revised December 2003) as issued and amended from time to time by the FASB.

By submitting a proposal, each respondent agrees to make available to the Company at any point in the bid evaluation process any financial data associated with the respondent and its proposed project so the Company may independently verify the respondent's information in the above matter. Financial data may include, but shall not be limited to, data supporting the economic life (both initial and remaining) of the facility, the fair market value of the facility, and any and all other costs (including debt specific to the asset being proposed) associated with the respondent's proposal. The Company may also use financial data contained in the respondent's financial statements (e.g. income statements, balance sheets, etc.) as may be necessary.

Section 3. Delivery and Interconnection Information

3.1 General information

Proposals that do not have an existing Large Generator Interconnection Agreement ("LGIA") or an existing interconnection queue position will be studied by Public Service to estimate electric interconnection and delivery requirements and costs. These procedures, and associated respondent responsibilities, are detailed in Appendix C.

3.2 ERZs

Appendix C also describes the ERZs that the Company is establishing pursuant to its requirements under Colorado Senate Bill 07-100 ("SB07-100"). The transmission upgrades contemplated as a result of the Company's SB07-100 compliance efforts are intended to allow delivery of energy from the ERZs. If the Company has received a certificate of public convenience and necessity to construct a transmission upgrade, the cost of the upgrade will not be included in the evaluation of proposals that utilize those upgrades.

Section 4. Proposal Content Requirements and Submission Procedure

4.1 Schedule Estimate

An indicative schedule for this RFP process is provided below.[10]

[10] The Company reserves the right to adjust this schedule appropriately, including (but not limited to) for changes to the regulatory calendar. The Pre-Bid Conference date is firm.

Activity	Date
RFP issued	January 9, 2009
Pre-Bid Conference	January 28, 2009
Notice of Intent to Respond Due	March 13, 2009
Proposals Due	April 10, 2009
Report to Commission of Phase II evaluation results[11]	August 9, 2009
Commission Decision	November 8, 2009

120-Day evaluation period

4.2 Minimum Requirements for Proposals

This section describes the minimum requirements that all proposals must satisfy to be eligible for consideration in this All-Source solicitation. Unless the Company in its sole discretion elects otherwise, proposals that do not comply with these requirements will be deemed ineligible and will not be considered further. The Company reserves the right to reject any bid and all bids.

- Proposals must include all applicable content requirements described in Section 4.3, including clear and complete written descriptions of all information requested, and a set of completed forms.
- Proposals must clearly specify all pricing terms in accordance with Section 2.3.
- Proposals must clearly demonstrate compliance with all power delivery requirements listed in Appendix C.
- Proposals must demonstrate an acceptable level of development and technology risk, as determined by the Company's evaluation team.
- For non-Section 123 proposals, the respondent's project development team must demonstrate that it has successfully completed the development, construction and commissioning of at least one utility scale and utility grade project with technology similar to the proposed project.
- For Section 123 proposals, the respondent's project development team must demonstrate that it has successfully completed the development, construction and commissioning of at least one utility scale and utility grade project.
- Respondents must demonstrate to the satisfaction of the Company that they can meet the security requirements contained in the Model PPA.
- Proposals must clearly demonstrate any financing requirements and an indicative financing structure (construction and permanent) for any proposed resources that will be delivered under the proposals. Respondents should

[11] The timing of the filing and CPUC Decision will depend in part on the IE's completion of its report to the CPUC.

include a description of how the current financial markets are likely to impact the respondent's ability to access the debt and tax equity markets.

- Each respondent must present clear and sufficient proof that it has or can secure an adequate and confirmed supply of generation equipment sufficient (at a minimum) to meet the required proposal.
- Respondents must provide the $10,000 bid fee (described in Section 4.8 below) for each bid submitted.

4.3 Proposal Content Requirements

This section outlines the content and format requirements for all proposals submitted in response to this RFP. Unless the Company in its sole discretion elects otherwise, proposals that do not include the information requested in this section will be ineligible for further evaluation, unless the information requested is not applicable or relevant to a given bid. The Company reserves the right to conduct any further due diligence it considers necessary to fully understand and evaluate bids prior to entering into any PPA.

Proposal Format

The first section of each proposal must contain an Executive Summary that provides an overview of the proposed generating resource characteristics, including any unique aspects or benefits. The second section of the proposal must include a completed set of applicable forms included in Appendix A. These forms will contain essential information about each bid. A separate set of forms and related information must be submitted with each proposal. The third section of the proposal must include additional information presented in narrative form under specific topic headings, with each topic heading beginning on a new page.

A complete proposal will include the following components:

1. Executive Summary
2. Complete set of applicable forms
3. Form attachments (as necessary to elaborate on form information)
4. Narrative Topics Discussion (topics described below)
5. Requested maps and electronic data

The proposal forms and topic headings are described below.

Proposal Forms

Form A	Notice of Intent to Respond
Form B	Bid Certification (including certification as to capital lease and FIN 46 issues)
Form C	Bid Cover Sheet
Form D	Pricing
Form E	Construction Milestones
Form F	Delivery Arrangements
Form G	Large Generator Interconnection Request
Form H	Representation Authorization

Form I	Technical Descriptions
Form J	Emission Rates
Form K	Energy Production Profiles
Form L	Natural Gas Supply

Appendix A and the individual forms include specific instructions for completion. Some information may be requested on more than one form. Although such requests may be redundant, respondents must provide the information requested on each applicable form.

Narrative Topics

In addition to completed forms, each proposal must also include a thorough written discussion of each of the following topics. The narrative topics should be organized under the following headings, with each heading beginning on a separate page.

- Development Experience
- Financial Information
- Project Description and Development Schedule
- Equipment Description
- Real Property Acquisition Description and Plan
- Permitting Plan
- Transmission Plan
- Community/State Reaction Assessment
- Operations and Maintenance ("O&M") Plan
- Exceptions to Model PPA
- Energy Production Profile
- Section 123 Resource
- Non-Quantifiable Externalities

Development Experience. All proposals must describe the respondent's qualifications and experience in developing, constructing, commissioning and operating generation facilities similar to the proposed facility, including the experience, qualifications and safety record of key personnel who will manage development and an overview of utility scale and utility grade projects the respondent has developed during the last 5 years. If an EPC team is in place, the proposal should identify the members of the team; if such a group is not in place, the proposal must set forth the respondent's plan for assembling such team (including process and timing).

Financial Information. All proposals must provide detailed financial information about the proposed project. This information shall include two years of audited financial statements or the equivalent for respondents and other responsible parties (including any entities that would provide parent guaranties of the respondents' obligations), whether the project will be financed as a recourse or non-recourse project, the percentages of debt and equity financing, and the expected cost of debt. In addition, respondents shall provide a detailed plan for financing the proposed project during construction and operation including the financing commitments that the bidder has obtained. Proposals shall also explain in detail the plan for meeting the security requirements outlined in the Model PPA and must set forth the credit rating (if any) of any entities that would provide parent guaranties of the respondents' obligations. Proposals must include an organization chart showing the entities that own the respondent's organization and a description of the respondents' organization structure (including primary and secondary businesses). Financial information may be provided primarily in electronic format so long as at least two (2) hard copies of the financial information are provided with each proposal.

Project Description and Development Schedule. All proposals for the construction of new generation facilities must set out a detailed description of the proposed project, including a description and plans for the proposed site and rights of way, utilities services, equipment configuration, transmission and interconnection, construction and equipment procurement, supply of spare parts, opportunities for future facility expansion, required permits, the nameplate capacity of the resource in MW (AC), the respondents' key consultants (if known) for fuel resource supply studies (e.g., solar, biomass) and permitting studies, and the respondents' construction contractors and prime subcontractors (if known). Such proposals must provide a detailed Gantt chart of project development activities developed using Microsoft Project or similar software (note that .PDF file-type is acceptable for submittal) that includes (at a minimum) entering major equipment and construction subcontracts, target completion dates for financing, engineering, permitting, equipment procurement, construction, startup and commissioning, and guaranteed dates for substantial completion. Proposals must describe the overall development strategy that will ensure that the project can be developed in time to meet the proposed commercial operation date. Respondents proposing Section 123 resource generation projects should describe the risks associated with deploying such new technology specifically as those risks impact the proposed commercial operation date and the first years of operation.

It is the Company's expectation that the Company will have first rights to the projects proposed in this All-Source solicitation for the period during the proposal review and approval process. In support of this, and included in this narrative, respondents must also provide any and all information which would restrict the respondent from providing the Company with exclusive rights to negotiate a PPA for the proposed project. Such restrictions could include, but are not limited to, prior active submission or participation in other RFPs, exclusivity rights granted to other parties, rights of first offer or refusal, purchase options, and active auctions for the project as applicable.

Equipment Description. Proposals should indicate for all major equipment (i) the name of the manufacturer and other vendors, (ii) models, (iii) key metrics and characteristics of the equipment, (iv) planned delivery dates, (v) contracting status, and (vi) performance history of the equipment. For bids employing photovoltaics, major equipment includes, at a minimum, photovoltaic modules, inverters, concentrators, and tracking units, as applicable; for solar thermal bids, major equipment includes, at a minimum, solar concentrators, receivers, tracking units, and turbine. For bids utilizing other energy resources, major equipment includes, at a minimum, the engine or turbine and any other equipment critical to gather or process the fuel prior to energy generation.

Real Property Acquisition Description and Plan. Proposals must provide a description of the status of real property acquisition necessary for the project that is sufficient for the Company to assess the completeness and sufficiency of the respondent's real property rights, including but not limited to:

- The status of current site ownership and/or control,
- The plan for acquiring any and all currently uncontrolled necessary real property rights to the project,
- Acreage of real property required for the project and a schedule for the completion of the real property acquisition process, and
- Any subdivision or zoning modifications and all city or county land use permits that will be required, such as conditional use, special use or other similar permits and approvals, which will be required for any phase of development, construction, or operations of the project.

Permitting Plan. Proposals must describe all federal, state and local permits and approvals that will be required for the project (other than land use permits included in the Real Property Acquisition Description and Plan), including, but not limited to, federal environmental assessments under the National Environmental Policy Act ("EA/EIS"), wastewater discharge permits, hazardous waste permits, and any hazard permits/determinations from the Federal Aviation Administration. Proposals must also provide written documentation evidencing that consultation has occurred with appropriate governmental agencies (for example, the Colorado Division of Wildlife or the U.S. Fish and Wildlife Service) responsible for reviewing potential project development impacts to state and federally listed wildlife species, as well as species and habitats of concern. Proposals must report on the status of all such permit applications and any feedback from permitting agencies. Proposals must provide the status of all required environmental permit applications (such as water, wastewater discharge, and hazardous waste permits) and any feedback respondents have received from permitting agencies. Proposals should specifically address any potential or expected environment or permitting challenges associated with the proposed heat transfer fluids or storage media.

Transmission Plan. All proposals should include a description of the respondent's plan to transmit power from the Project to the proposed Point of Delivery to the Public Service transmission system as described in Appendix C. The information should include a description and expected route of any radial transmission line dedicated principally to the Project if known, including a summary of the status of obtaining requisite easements and alternatives. If any new FERC-regulated transmission or any upgrades to non-Public Service transmission will be required to deliver power from the Project to the proposed point of delivery ("New Transmission"), the proposal also should include a complete description of the required New Transmission including (i) the owner and developer of the New Transmission, (ii) the complete expected route for the New Transmission, (iii) the voltage and capacity of the New Transmission, (iv) the status of planning, permitting, financing and construction of the New Transmission, to the extent known to the respondent, (v) the location of the interconnection of the Project into the New Transmission, (vi) whether the respondent's Project, if successful, would be sufficient for the New Transmission to be built without the participation of other power projects, and (vii) if not, what other projects would need to be built, in what time frame, to allow the New Transmission to be built in time for the respondent to meet its scheduled in-service date.

Community/State Reaction Assessment. Each respondent must present a current assessment of, and a plan for continuing to monitor, local community and state reaction to the project, and a plan to work with the local community on project issues. Such plan might include the following elements:

- A list of the references used to assess the community reaction, and the methodology used to draw conclusions,
- A list of key local contacts interviewed and their opinions,
- An assessment of the local community reaction at the time of the bid,
- An action plan for working with the local community/state to successfully complete the project and
- A description of the respondent's proposed conflict resolution methodology.

Operations and Maintenance ("O&M") Plan. Respondents shall summarize their O&M plans and labor arrangements for the generation facilities associated with their proposals.

Exceptions to Model PPA. In support of the Company's efforts to complete project evaluation and contract negotiations in a timely manner, respondents shall review and provide exceptions and/or comments to the Model PPA. To the extent that the validity of a respondent's proposal and/or the respondent's ability to execute a PPA is contingent upon material changes to the language in the Model PPA, respondents should specifically identify the terms in the Model PPA they propose to change and should summarize their proposed changes to such terms. To the extent that a respondent wishes to propose changes to the Model PPA that (if accepted by the Company) would reduce the respondent's proposed prices, the proposal should specifically identify such changes and the associated price reduction. To the extent practicable, respondents should develop exhibits, schedules, attachments and other supplemental documents required by the Model PPA.

Solar Energy Production Profile
Respondents must document the source of meteorological data used in the required generation production calculations provided on Form K, if applicable. Energy production profiles for solar facilities that are based on theoretical modeling or a combination of on-site metered data and modeled data will be accepted. However, regardless of the source of this data, respondents must provide the resource data measurement method used to derive the data (for example, whether it was collected on site, at a nearby station, or inferred from satellite data), must identify the number of years of solar data available and employed in developing the monthly average expected hourly generation

calculations required on Form K1, and must describe the accuracy of that data. If the measurement method relies entirely—or in part—on theoretical data, the respondent should include background information on the entity that conducted the study, the technology employed and any track record attesting to the accuracy of the methods used.

To the extent a proposal includes an energy storage technology, respondents should describe, in detail, the storage dispatch logic inherent in the hourly results provided. As the Company proposes a tolling structure for those projects that propose fuel backup/hybridization, respondents should not include any fossil fuel generation estimates on Form K1 or K2.

Non-Solar Energy Production Profile

All proposals involving use of wind generation resources (e.g., wind with storage) must provide information on expected annual energy production for the wind component as described in the 2009 RFP for Wind Resources. With regard to any storage component, proposals should include the expected energy production profile from storage on Form K1 of this Semi-Dispatchable Renewable Capacity RFP as well as a narrative description of the expected generation profile from storage including any limitations.

For all other non-solar proposals the expected energy production profiles should be provided on Form K1 of this Semi-Dispatchable Renewable Capacity RFP and a description of the impact on the generation profiles of the resource intermittency should be described in this narrative section. Examples might include expected seasonal generation patterns from a run-of-river hydro facility or daily generation patterns from a biomass facility that proposes to run only during workday hours.

Section 123 Resource

Respondents should indicate whether or not they believe their project meets the requirements of a Section 123 resource. If Respondent claims that its project is a Section 123 resource, it should provide sufficient justification for that claim.

Non-Quantifiable Externality Benefits

Respondents may include a qualitative assessment and discussion of how their proposed project incorporates the following non-energy factors including, but not limited to:

- Economic development,
- Resource diversification, and
- Environmental benefits associated with emissions reductions and other environmental impacts beyond permit compliance.

The Company and the IE will provide a narrative summary of the Respondent-provided externality benefits associated with each likely portfolio of resources to the Commission. The Commission has indicated that it will compare the risks and benefits (including the non-quantifiable externalities) of the proposed resource portfolios from the Company and the IE during Phase II of the Company's 2007 CRP. Proposals that contain exceptional externality benefits may be given preferred consideration in the ranking of proposals.

4.4 Pre-Bid Conference

Time: 9:00 AM MST
Date: January 28, 2009
Location: 550 15th Street, Suite 019 (Basement)
Denver, Colorado 80202

Public Service will webcast the meeting and will provide means for remote, electronic participation by potential All-Source RFP respondents. Public Service will post information concerning webcast access and remote participation on the Public Service 2009 All-Source RFP website at www.xcelenergy.com (Select Top Menu item "*Company*" then select Left Menu item "*About Energy and Rates*" then select Left Menu item "*Energy RFPs*" and the link for the 2009 PSCo All-Source RFP).

Interested parties are encouraged to provide written questions to the Company's RFP Project Manager by email prior to the pre-bid meeting. The Conference will be interrupted by a lunch break from 12:00 PM till 1:00 PM. The Conference will conclude at 4:00 PM or when topics are exhausted. Questions remaining at 4:00 PM will be addressed by posting answers on the above-referenced website. Copies of any presentation materials used by Public Service at the Pre-Bid Conference will be made available to participants at the Conference in Denver and at the above-referenced website. Participants are encouraged to have available copies of the 2009 All-Source RFPs while attending the Conference. A summary of the bid conference proceedings, including submitted questions and answers, will be prepared by the Company posted on the above-referenced website.

4.5 Notice of Intent to Respond

While not mandatory, respondents are encouraged to submit a completed Form A, Notice of Intent to Respond. Respondents that intend to submit a proposal should submit a non-binding Notice of Intent to Respond (NOIR), a form of which is included in Appendix A. Please submit the completed NOIR no later than 4:00 P.M. Mountain Time on March 13, 2009 to the Company's RFP point of contact noted below by e-mail (in PDF format), registered or certified mail, or overnight courier. There is no fee required to submit an NOIR.

4.6 Proposal Submission Deadline

Bids will be accepted until 4:00 P.M. Mountain Time on the date indicated in Section 4.1. All bids must be transmitted by express, certified or registered mail, or hand delivered to the Company's RFP point of contact at the following address:

Public Service 2009 All-Source RFP point of contact:

PSCo 2009 All-Source RFP Project Manager
Xcel Energy Services Inc.
550 15th Street, Suite 1000
Denver, Colorado 80202

Email: PSCo2009AllSource@xcelenergy.com

Proposals received later than the due date and time indicated will be rejected and returned unopened, unless the Company determines, at its sole discretion, to consider such proposals. With the exception of the financial information of which only two (2) hard copies are required, seven (7) bound hard copies of the proposal must be included in the submittal. In addition, respondents must submit two (2) electronic copies on CD with completed forms in a Microsoft Office format. Respondents are requested to provide Office documents in file formats compatible with Office 2003, i.e., not docx or xlsx formats.

Proposals must be submitted in a sealed package with the following information shown on the package:

Response to PSCo 2009 RFP for Semi-Dispatchable Renewable Capacity Resources, Confidential Sealed Bid Proposal

The respondent's company name and address must be clearly indicated on the package containing the proposal.

4.7 Information Policy

To obtain additional information about this RFP, respondents may only submit written requests to the RFP Project Manager. Questions or requests will only be accepted via email. The Company will maintain a log of all inquiries and coordinate the preparation of written responses. Once a response is prepared, the Company will forward the response to the inquiring party and, at the Company's sole discretion if the response is germane to all other respondents, all other respondents that have provided an email address. Parties without email addresses will not receive these responses. The Company has established this information policy to ensure that all respondents have the same knowledge about the bidding and evaluation process.

4.8 Bid Evaluation Fees

All respondents are required to pay to the Company a bid evaluation fee of $10,000 with each proposal submitted. The bid evaluation fee will be used to compensate the Company for expenses incurred in evaluating the generation bid. Public Service may deem proposals that do not satisfy the requirements for a single proposal as multiple proposals, each of which would require a separate bid evaluation fee. For example, each proposal that triggers interconnection studies for multiple points or levels of interconnection would be deemed separate proposals for each such point or level. In addition, proposals offering multiple commercial operation dates for the same project or facility will be deemed as multiple proposals. If the Company deems a respondent's proposal to be multiple proposals, the Company will notify the respondent and allow it to elect to pay the incremental bid fee or to revise its proposal to comply with the Company's requirements for a single proposal.

Checks should be made out to "Public Service Company of Colorado" and must be included with the proposal. Bid evaluation fees are non-refundable.

4.9 Clarification of Proposals

While evaluating proposals, the Company may request clarification or additional information about any item in the proposal. Such requests will be sent to respondents by the RFP Project Manager, typically, and respondents are required to provide a written or electronic response back to the RFP Project Manager within five (5) business days, or the Company may deem the respondent to be non-responsive and either suspend or terminate evaluation of the bid. Respondents are encouraged to provide an alternate point of contact to ensure a timely response to clarification questions.

4.10 Confidentiality

Respondents are allowed to identify any information in their proposals that respondents claim should be considered to be confidential or proprietary. Nonetheless, the Company reserves the right to release all proposals to its affiliates and to its and such affiliates' agents, advisors, consultants, and the IE for purposes of proposal evaluation. The Company will, to the extent required by law, advise each agent, advisor or consultant that receives such claimed confidential information of its obligations to protect such information. In addition, all information, regardless of its confidential or proprietary nature, will be subject to review by the Commission and other governmental authorities and courts with jurisdiction, and may be subject to legal discovery. It is not the Company's intent to enter into any separate confidentiality, non-disclosure, or similar agreements as a condition to receiving a respondent's proposal.

4.11 Addenda to RFP

Any additional responses required from respondents as a result of an Addendum to this RFP shall become part of each proposal. Respondents must list all submitted Addenda at the bottom of the Proposal Certification Form.

Section 5. Evaluation and Bid Criteria

The objective of the Company's All-Source evaluation is to identify portfolios of proposals that meet the resource needs identified in this solicitation in a reliable and cost-effective manner while achieving the goals of the Commission-approved CRP.

As described below, the evaluation process will include an assessment of both economic and non-economic criteria.

5.1 Evaluation Process

An evaluation team, made up of various groups within the Xcel Energy Services and the Company will evaluate proposals. The RFP Project Manager, subject matter experts from Xcel Energy Services and the Company, and the IE may contact respondents directly during the evaluation process for the purposes of clarifying proposals. The Company will also cooperate with, and provide access to information provided by respondents, to the Independent Evaluator ("IE") as required by RP Rule 3610. The IE will conduct an evaluation of proposals independent of the Company using a similar process as that set forth below.

Proposals will be evaluated using a multi-step process as follows:

Step 1 – Bid Eligibility Screening

The information provided in each proposal will first be evaluated for completeness and consistency with the content requirements outlined in Section 4.3 of this RFP. Preliminary due diligence will also be conducted at this stage to identify any "fatal flaws" associated with proposals, such as an unacceptably high level of development or technology risk.

As a result of this eligibility screening review, the Company may either eliminate proposals from further consideration, or contact respondents to clarify information or request additional information. Given the short amount of time allotted to evaluate the bids, the Company will limit follow up contacts to bids that meet the minimum eligibility requirements described in Section 4.2.

The Company will notify each respondent that has one or more proposals if they have satisfied the eligibility screening described in Step 1.

Step 2 – Transmission Assessment and Initial Economic Evaluation

While not entirely concurrent, the activities described in Steps 2.A., 2.B. and 2.C. below will overlap to some extent.

A. Interconnection Cost Estimates

The Company will determine or verify interconnection cost estimates provided by bidders. If substantial differences occur, the Company will provide its cost estimates to the applicable bidders so that they can update their bid pricing, as they deem appropriate. Such bidders must submit final bid pricing back to the Company within 5 calendar days of the date the interconnection cost estimates are provided to such bidders.

B. Transmission Upgrade Schedule Assessment

Some or all of the bids will also be evaluated to assess the general siting, permitting, and construction time requirements associated with the Public Service transmission network upgrades, including network upgrades for interconnection, that may be needed for each proposal to:

a) interconnect the proposed generation with the Public Service transmission system,

b) deliver the entire proposed capacity and energy to the Company's customers, and/or

c) deliver the entire proposed capacity and energy from a third party transmission system to the Public Service electric system.

The impact of these analyses on a respondent's proposed schedule will be a factor in the evaluation of its proposal.

C. Initial Economic Screening

All remaining proposals will be screened based on individual bid economics.

The objective of this initial economic screening is to reduce the remaining bid pool to a more manageable size that will then be moved forward for dynamic optimization within the Company's computer modeling process. Using traditional spreadsheet analysis tools, such as screening curves that calculate and compare resource costs at estimated capacity factors, the Company will evaluate the economics of individual bids. Proposals that are determined to be more costly than proposals for similar resources will be eliminated from further consideration.

Step 3 – Non-Price Factor Analysis

This analysis will assess the non-price characteristics of the proposals. Non-price factors that will be assessed include, as applicable and without limitation, the following:

- Financial strength of the respondent
- Financing plan, including ability to utilize tax advantages
- Development, construction and operation experience
- Generator technology, availability, and warranties
- Meteorological data (if applicable) and quality and availability of the fuel resource
- Environmental permitting and compliance
- Land use permitting and zoning
- Other permitting
- Real property acquisition/site control progress and plan
- Project operational characteristics
- Scale of the project
- Geographic suitability with respect to Appendix C
- Community support for the project
- Transmission access plan feasibility and arrangements

- Transmission upgrade schedule assessment
- Construction and equipment supply plans and arrangements
- Project execution planning
- Accreditability of capacity to meet reliability needs
- Accounting assessment
- Section 123 resource characteristics
- Externality benefits

Proposals that are determined to be infeasible will be eliminated from further consideration.

.

Step 4 – Portfolio Analysis of Proposals

The costs and operational characteristics of any Company proposal and each remaining bid will be input into the Company's Strategist™ planning model. The Strategist™ model will be used to construct portfolios of bids that meet the capacity and energy projections of the Public Service system, as well as the various objectives of the resource plan and Commission decisions. The Strategist™ model simulates operation of proposals together with the Company's existing resources (and to an extent, the regional power market), while keeping track of all associated fixed and variable costs of the Company's entire system.

In accordance with the Commission's RP Rules, Strategist™ will be utilized to develop portfolios that minimize the net present value of revenue requirements over the forty-year planning period (i.e., 2007-2046). The model will also be used to develop alternative resource portfolios that represent the costs and benefits from increasing amounts of Section 123 resources, increasing amounts of Company-owned resources, and considering proposals claiming externality benefits. Portfolios will be developed in accordance with the scenario analysis directives of the Commission and will include portfolios that assume varying levels of demand-side management.

The results from the scenario analysis process, together with a consideration of due diligence findings (described in Step 3), Company ownership benefits, Section 123 resource benefits, and non-quantifiable externality benefits will form the basis for selecting portfolios that will ultimately be presented to the Commission.

The general planning assumptions that will be used in the development of resource portfolios are included in Appendix B to this RFP.

Step 5 – Phase II Report to Commission

Upon completion of the evaluation process, both the Company and the IE will submit reports to the Commission pursuant to the requirements of RP Rule 3610(h) for the Commission to complete its Phase II evaluation.

5.2 Independent Evaluator

The Company will work with an independent evaluator ("IE') approved by the Commission to assist the Commission with the complex issues and analyses involved in utility resource modeling and selection. One of the responsibilities of the IE will be to report to the Commission its independent assessment of the proposals submitted in response to the All-Source solicitation. The IE will require access to all respondent information necessary to perform a complete evaluation of proposals.

The Company and respondents will need to provide the IE with data and information necessary to support this independent analysis. The IE is to be engaged and working concurrently with the Company's performance of Steps 1 through 5 of the evaluation process described above and as directed by the Commission.

5.3 Phase II Commission Evaluation

The Commission will review the evaluation reports submitted by the Company and the IE in accordance with RP Rule 3610(j), and will issue a final decision on the Company's final 2007 CRP within 90 days of receipt of those reports.

Appendix A

Proposal Forms and Instructions

As discussed in Section 4, the completed forms, attachments and narrative topic discussions, will comprise a complete proposal, except that Form G should be completed only by respondents without an existing LGIA or an existing interconnection queue position. The contents of each form and any special instructions for completing the forms are described below. **These forms can be downloaded from the RFP web site in a format appropriate for respondent input**.

If additional space is needed to elaborate on information requested on any form, please attach additional sheets with the heading "Form [__] – Additional Information."

If certain information is requested that does not apply to the proposal, the respondent must indicate that the information is not applicable. If appropriate, the respondent should explain why the information is not applicable.

In addition to submitting seven (7)[12] hard copies of the proposal, respondents must also include two (2) CDs with the completed Forms in executable format (i.e., not PDF). The Company will provide the IE with one hard copy of the proposal, the financials, and CD.

[12] Respondents are required to submit only two (2) hard copies of their financial data with each proposal.

Appendix B

General Planning Assumptions

The following planning assumptions will underlie the evaluation of proposals received in response to the Company's All-Source solicitation. Note that the following is not a complete listing of all assumptions that will be applied in the evaluation process. Further note that the assumptions noted below represent "base case" assumptions. Sensitivity analyses will be performed in which certain of these assumptions are altered in accordance with Commission directives.

- **Utility Discount Rate and Cost of Capital**

The Company will use a discount rate based on the Company's last Commission-approved weighted after-tax cost of capital. Currently, this rate is 7.88%.

- **General Inflation**

This assumption will apply to certain existing Company resource costs and future generic resource costs used in the evaluation (e.g., Variable Operations and Maintenance ("VOM") and Fixed Operations and Maintenance ("FOM")). The general inflation rate will be an annual escalation factor of 2.5%.

- **Transmission Costs**

The Company will allocate or assign transmission delivery costs in accordance with CPUC Decisions No. C08-0929 and C08-1153 in Docket No. 07A-447E. In sum, the costs of new transmission facilities for which the Commission has granted certificates of public convenience and necessity will not be included in bid evaluation; the Company will treat these transmission project costs after a CPCN is granted as a part of existing network costs. In contrast, the costs of any new transmission facilities for which a CPCN has not yet been granted, including transmission facilities that the Company will propose in the ongoing SB07-100 process, will be assigned to portfolios of proposals that require this new transmission. Projects that utilize available transmission capacity will not have additional delivery costs assigned to them. Furthermore, for proposals that do require new transmission facilities, the Company will assign costs based on the estimated amount of the new transmission capacity that will be utilized by the proposal(s) (i.e., if proposal only utilizes 50% of the new transmission capacity then they will be assigned 50% of the estimated costs of the new transmission).

- **Capacity Credit for Intermittent Resources**

Existing wind facilities and new wind proposals will be given a capacity credit in the evaluation process equal to 12.5% of their nameplate capacity. Capacity credit for intermittent solar resources will be provided to the Commission and prospective bidders no later than 60 days prior to the date responses are due to this All-Source solicitation. Capacity credit for other intermittent resources will be determined on a case-by-case basis.

- **Integration Cost for Intermittent Resources**

Integration costs for wind resources will be based on the results of the Company's 20% wind integration study and the final written Commission decision addressing this issue.

Since wind integration costs are correlated to the gas prices, changes in gas price assumptions compared to what was assumed in the wind integration studies will result in corresponding changes in wind integration costs.

Integration costs for intermittent solar resources will be provided to the Commission and prospective bidders no later than 60 days prior to the date responses are due to this All-Source solicitation.

Integration costs for other intermittent resources will be based upon the Company's most recent studies.

- **Gas Price Forecast**

The Company will use updates of the natural gas price forecasts approved by the CPUC in Decision C08-0929, which consists of a combination of long-term gas price forecasts from Cambridge Energy Research Associates ("CERA"), PIRA Energy Group ("PIRA"), Global Insights ("GI"), and the current forward price as represented by the New York Mercantile Exchange ("NYMEX") Gas Futures Contract. The Company will utilize a simple average of the forecasts from these four entities to develop a long-term gas price forecast for Henry Hub, Louisiana (the location applicable to the NYMEX contract).

The Company will adjust the long-term Henry Hub forecast by applying a forecast of the basis differential, to obtain a long-term commodity forecast for the Colorado Interstate Gas ("CIG") Rocky Mountain index, the index for the area where the Company purchases most of its gas supplies. To this commodity forecast, the Company will add the cost of local transportation and fuel to provide a delivered to plant forecast. In order to compensate for gas price volatility, the Company will also add the cost of an "at-the-money" call option to the commodity price forecast.

- **Planning Period – 40 yrs (2007–2046)**

- **Existing Company Owned Plant Lives**

Existing Company owned generation facilities will be represented to retire by their respective accounting book dates per the Settlement Agreement in Commission Docket No. 06S-234G

- **CO_2 Cost Adder**

In its economic screening and portfolio optimization processes, the Company will impute a CO_2 cost of $20/ton beginning in 2010 and escalating at 7.0% per year beginning in 2011 through 2046. This cost adder will be applied to all existing fossil fuel generation facilities and proposed fossil fuel generation resources and proposed renewable energy generation facilities with gas backup/hybridization as a variable cost affecting unit dispatch.

Appendix C

Transmission Costs and Energy Resource Zones ("ERZs")

1. **Power Delivery Requirements**

Proposals must specify delivery of capacity and energy to the Public Service system at a point of delivery within or at the boundary of the Public Service Control Area and at a Public Service-owned transmission facility. All respondents should carefully review Section 8 of this Appendix C, which may assist respondents in identifying and selecting advantageous zones and locations for projects.

2. **Proposals Requiring Third-Party Transmission Service**

For proposals that will require third-party transmission service(s) for the delivery of capacity and energy to the bid-specified point of delivery on the Public Service system, respondents are responsible for any interconnection, electric losses, transmission and ancillary service arrangements required to deliver the proposed capacity and energy to the bid-specified point of delivery on a firm basis. Such proposals must identify all third-party interconnections, electric losses, transmission and ancillary service providers, components and costs, provide a complete description of those service arrangements and provide documentation that such service(s) will be available to a PPA respondent or the Company during the full term of service proposed. The cost of all such third party services, for which a PPA respondent intends to seek compensation from the Company, must be included in the bid prices provided on the applicable forms. Respondents should recognize that wheeling and other costs associated with such services may adversely affect the cost-effectiveness of their proposals.

3. **Interconnection Costs**

Proposals that will require a new or upgraded electrical interconnection to the Public Service transmission system should include in their proposal pricing any costs for the generator interconnection facilities. To clarify, these are the facilities between the generation project and the point of interconnection to the Public Service transmission system (these types of facilities are commonly referred to as "Generator Interconnection Facilities" and "PSCo-Owned, Customer Funded Interconnection Facilities" in the LGIP). Because these facilities are not considered a part of the transmission system, they are part of the cost of the generation project and must therefore be incorporated in the proposal pricing.

If the bidder has an active LGIP request, the bidder should provide the LGIP identifier(s) associated with its project in its proposal. Bidders are urged not to submit a generation interconnection request or transmission service request pursuant to the Xcel Energy Open Access Transmission Tariff ("OATT") to receive these interconnection cost estimates.

As discussed in Section 5.1 of this RFP, proposal-specific cost estimates of Generator Interconnection Facilities provided by bidders in Form D will be verified or determined by the Company and, if required, Company estimates will be provided back to bidders so that they can update their bid pricing as needed. Such bidders must submit final bid pricing back to the Company within 5 calendar days of the date the interconnection cost estimates are provided. These estimates and other transmission and interconnection-related information will be posted, as required, on the Company's OASIS[13] in a manner that preserves individual bidder confidentiality. Information posted on the Company's OASIS will not identify bidder Company name but rather will identify location of proposed interconnection, generation capacity and type proposed, and a summary of the study results.

4. Application of the Xcel Energy OATT

The Company anticipates that all transmission usage rights associated with bids selected through the RFP will be "network" use rights held by the Company. Under FERC Order No. 888[14] where the Company will hold the transmission service rights, the Company must provide non-discriminatory access to its transmission system, and must designate network resources in the same manner as a similarly situated OATT customer. In addition, under FERC Order No. 2003 (August, 2003), Order No. 2003-A (March 2004) and Order No. 2003-B (January 2005),[15] all new requests for interconnection of a large generator (20 MW or larger) to the Public Service transmission system requested after January 20, 2004, including interconnection requests associated with this RFP, must be administered in a non-discriminatory manner in compliance with the LGIP contained in the Xcel Energy OATT.

Pursuant to the Representation Authorization Form (Form H of Appendix A) to be executed and submitted by each bidder, the RP&A group will act as the Authorized Representative for each bidder for purposes of submitting any and all Interconnection Requests for portfolios of proposals to have Interconnection Feasibility and System Impact Studies performed under the LGIP provisions of the OATT. Form H also acts as the Consent form pursuant to 18 CFR 358.5(b)(4) (Order No. 2004) authorizing the Transmission Function to share certain non-public transmission information related to the transmission interconnection and network upgrade projects associated with the bid to the RP&A group for the limited purpose of facilitating analysis of the bid(s).

---

13 Information regarding posted studies may be found on the public site http://www.PSCo OASIS.com/wtpp/psco_studies.html. This website does not require a digital certificate to view, while the Company's OASIS site located at http://www.westtrans.net does require a digital certificate.

14 Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities and Transmitting Utilities, Order No. 888, F.E.R.C. Stats. & Regs. 31,036, (1996) ("Order No. 888"), order on reh'g, Order No. 888-A, F.E.R.C. Stats. & Regs. 31,048 (1997), order on reh'g, Order No. 888-B, 81 F.E.R.C. ¶ 61,248 (1997) ("Order No. 888-B"), order on reh'g, Order No. 888-C, 82 F.E.R.C. ¶61,046 (1998), aff'd New York, et al. v. FERC, 122 S.Ct. 1012 (2002).

15 *Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, 68 Fed. Reg. 49,845 (Aug. 19, 2003); FERC Stats. & Regs. ¶ 31,146 (2003); *reh'g granted*, Order No. 2003-A, 106 FERC ¶ 61,220 (March 5, 2004), 69 Fed. Reg. 15932 (March 26, 2004); Order No. 2003-B, 109 FERC ¶ 61,287, 70 Fed. Reg. 264 (January 4, 2005).

5. LGIP Interconnection Studies

Given the short period of time available to evaluate bids, the Company's evaluation team and the Company's Transmission Planning Function will employ an abbreviated process for estimating the transmission Network Upgrades, associated costs and construction timeframes necessary to deliver power from proposed facilities to customer loads. In general, this abbreviated process will consist of four stages:

Stage 1 – The Transmission Access group (a department within Resource Planning & Acquisition) will rely on existing LGIP studies posted on the Public Service OASIS to determine bid-specific interconnection and delivery facilities and costs.

Stage 2 – The evaluation team will develop a number of portfolios of bids that will meet the Company's needs and the various Commission directives. The Transmission Access group will provide estimates of the network facilities and upgrades required for each portfolio and provide that information to the Transmission Function.

Stage 3 – The Transmission Function will review the Transmission Access group's estimates of network facilities and upgrades and modify as deemed appropriate. The resulting information will be used in selecting the portfolios of bids that are presented to the Commission for consideration at the end of the 120 day evaluation period.

Stage 4 – Depending on the number of bids received and their location, the Company may decide to also utilize the "Resource Solicitation Cluster" provisions contained in the Xcel Energy OATT for providing more refined estimates of network facilities and upgrades necessary to deliver power from portfolios of bids to customer loads. If this process is utilized, the Transmission Access Group will submit portfolios into the LGIP for consideration. A given portfolio submitted into the LGIP will occupy a single queue position (based on the date of the portfolio Interconnection Request) for the required Interconnection studies. This Stage will likely not be completed prior to the end of the 120 day evaluation period.

Each bid passed to the Transmission Function for study in the Resource Solicitation Cluster that requires a new or expanded transmission interconnection must provide an Interconnection Request deposit of $50,000 (or such other amount as is required under the LGIP provisions of the Xcel Energy OATT)[16] which will be forwarded to the Transmission Function to pay the cost of Feasibility and/or System Impact studies that will be performed for each portfolio.

Once the Transmission Function has completed the Feasibility and/or System Impact studies, the study results will be posted on the Company's OASIS in a

16The bidders must demonstrate "site control," which the OATT defines as "documentation reasonably demonstrating: (1) ownership of, a leasehold interest in, or a right to develop a site for the purpose of constructing the Generating Facility; (2) an option to purchase or acquire a leasehold site for such purpose; or (3) an exclusivity or other business relationship between Interconnection Customer and the entity having the right to sell, lease or grant Interconnection Customer the right to possess or occupy a site for such purpose."

manner that preserves individual bidder confidentiality. Respondents ultimately selected through this process must work directly with the Transmission Function from this point to complete the LGIP process and execute an LGIA.

Respondents that fail to provide the required LGIP study deposits at any time will be removed from the interconnection queue and will be removed from further consideration in the evaluation process. As required by the OATT, the Transmission Function will refund to bidders all LGIP study fees not expended or will bill bidders for any study costs exceeding the deposited amount. The RP&A group will act as each bidder's Authorized Representative only through the System Impact Study phase.

6. **Network Designation and Funding of Transmission System Upgrades For Interconnection**

- Network Resource Designation:

  As indicated above, the Company anticipates that it will declare each proposal selected through this RFP as a Network Resource of the Company, and that the Company will bear the cost of any network transmission service on the Public Service system (whether or not procured under the OATT) for a proposal that is selected and achieves commercial operation. Each short-listed respondent not requiring a new transmission interconnection (e.g., either a generator already connected to the Public Service transmission system or each off-system generator not connected to the Public Service transmission system) and each portfolio of bids requiring new or expanded generation interconnections will be evaluated as proposed designated Network Resources pursuant to Article III of the OATT.

- Funding of Network Upgrades for Interconnection:

  For purposes of achieving an interconnection, the Company's LGIP provides for the option of funding the network upgrades or requiring the interconnection customer (e.g., the respondent) to fund such upgrades and receive revenue credits based on future transmission services used by the interconnection customer or through some other refunding mechanism.

  The Company will make a determination about which, if any, interconnection costs are to be financed by respondents after it completes the LGIP studies that are conducted in connection with this RFP. If the Company determines that certain infrastructure costs are to be funded by respondents, any financing arrangements will be negotiated as part of the LGIA. Also, respondents should refer to Section 10 of this Appendix C to identify those ERZs in which projects may be sited to minimize network charges.

7. **Energy Resource Zones**

- Colorado Senate Bill 07-100

SB07-100, passed by the Colorado legislature and signed by the governor, includes the following findings:

a) a robust electric transmission system is critical to ensuring the reliability of electric power for Colorado citizens,

b) Colorado's vibrant economy and high quality of life depend on the continued availability of clean, affordable, reliable electricity and

c) therefore Colorado utilities should continually evaluate the adequacy of electric transmission facilities throughout the state and should be encouraged to promptly and efficiently improve such infrastructure as required to meet the state's existing and future energy needs.

Under SB07-100, the Company is required to:

a) designate "energy resource zones," which are geographic areas in which transmission constraints hinder the delivery of electricity to Colorado consumers, the development of new electric generation facilities to serve Colorado consumers, or both,

b) develop plans for the construction or expansion of transmission facilities necessary to delivery power consistent with the timing of development of energy resources located in or near such zones,

c) consider how transmission can be provided to encourage local ownership of renewable energy facilities and

d) submit proposed plans and applications for CPCNs to the Commission for the transmission projects described in paragraph b) above.

- Designation of Energy Resource Zones

  Pursuant to the requirements described in paragraph a) above, the Company has designated four (4) ERZs.

  - Zone 1: In Northeast Colorado, Zone 1 includes all or parts of Sedgwick, Phillips, Yuma, Washington, Logan, Morgan, Weld and Larimer Counties.
  - Zone 2: In East Central Colorado, and including all or parts of Yuma, Washington, Adams, Arapahoe, Elbert, El Paso, Lincoln, Kit Carson and Cheyenne Counties.
  - Zone 3: Southeast Colorado, including all of parts of Baca, Bent, Prowers, Kiowa and Las Animas Counties.
  - Zone 4: San Luis Valley, including all or parts of Costilla, Conejos, Rio Grande, Alamosa and Saguache Counties.
  - Zone 5: South-Central Colorado, including all or parts of Huerfano, Pueblo, Otero, Crowley and Las Animas counties.

- Transmission Expansion Plans

A. Company's 2007 SB-100 Filing

As more fully explained in the Company's 2007 filing, the Company submitted transmission expansion plans that will increase the import capability from certain Zones in certain time frames. A copy of the full text of the Company's October 31, 2007 SB07-100 filing may be found at www.rmao.com/wtpp/sb100.html. The status of projects listed in the 2007 filing are described below.

- Zone 1: The Company has a near term and long term plan to increase the injection capability from Zone 1. The near term plan is to upgrade the existing 230kV Pawnee-Smoky Hill and Pawnee-Daniels Park lines to 637 MVA. These upgrades were completed in 2008 and provide approximately 300 MW of additional injection capability from the Pawnee region.

  The long-term plan for Zone 1 is construction of a new 345kV line from Pawnee to Smoky Hill. This line will provide approximately 500 MW of additional injection capability from the Pawnee Region, over and above the 300 MW from the near term upgrades. The Commission granted a CPCN for this SB07-100 transmission project in 2008. This new line has a completion time frame of approximately 65 months, and we expect it to be in service by summer 2014.

- Zone 2: Except with respect to the Eastern Plains Transmission Project ("EPTP"), the Company provided no transmission expansion plans for Zone 2.

- Zone 3: The Company proposed a near term upgrade to increase the capability out of Zone 3 by a nominal amount. That project, however, was not constructed.

- Zone 4: The Company has approximately 200 MW of excess injection capability during peak periods that could accommodate new generation in this Zone. This amount reduces to approximately 175 MW during off-peak periods.

B. Company's 2009 SB-100 Filing

The Company filed a 2009 SB-100 report with the CPUC on November 24, 2008. That document describes a number of new transmission projects that increase the injection capability from all five of the Energy Resource Zones. A copy of the full text of the Company's November 2008 SB-100 report can be found at www.rmao.com/wtpp/sb100_2009.html.

Appendix D

Model Power Purchase Agreement

In the Matter of:

The Application of Tri-State Generation and Transmission Association, et al.

JOEL BLADOW

Date Taken: July 17, 2009

1640 Grant Street, Suite 100
Denver, Colorado 80203

FAX: 303-830-8505
depo@richardsonreporting.com

additional mileage, it turns out it is not the cheapest way to get out of the valley.

A Why is there additional mileage, is the question you are missing. There is additional mileage because you are connecting it to the north to reduce a different piece of the project's cost.

Q There is six miles additional between the Walsenburg substation and Calumet; right?

A I would have to look.

Q That is not where the 20 miles is coming from, is it?

A I'm not sure where the 20 miles is coming from in terms of estimates. I didn't come up with the mileage estimate.

Q If you look at the 2008 report, it says the mileage estimates were done by straight-line analysis.

A Okay.

Q If you take a look at Exhibit 4, the corridor map, and if you just draw a line from the San Luis substation over to Walsenburg, it's pretty clear that was never going to be a straight line, isn't it?

A I don't know.

Q Well, one, it crosses pretty close to Blanca Peak.

A Great Sand Dunes.

Q Well, Great Sand Dunes National Park you can't cross; right?

A That is probably a safe assumption.

Q You can't go over a 14,000 foot peak.

A I wouldn't want to.

Q And so what you are proposing now goes well south and then back north; right?

A Yes.

Q So it's about 20 miles longer than a straight-line estimate; right?

A Okay.

Q Now, the proposals to the north, you have existing lines up there, and they are pretty straight, aren't they?

MR. SINGER: Object to the question.

THE WITNESS: I don't know.

MR. SINGER: It's imprecise.

Q (By Mr. Douglas) Do you think existing lines running to the north appear significantly less curved --

A Well, the problem --

Q -- than the San Luis to Walsenburg line?

MR. SINGER: Object to the question.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

Docket No. 09A-324E

IN THE MATTER OF THE APPLICATION OF TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC. (A) FOR A CERTIFICATE OF) PUBLIC CONVENIENCE AND NECESSITY FOR THE SAN LUIS VALLEY-CALUMET-COMANCHE TRANSMISSION PROJECT, (B) FOR SPECIFIC FINDINGS WITH RESPECT TO EMF AND NOISE, AND (C) FOR APPROVAL OF OWNERSHIP INTEREST TRANSFER AS NEEDED WHEN PROJECT IS COMPLETED.

AND

Docket No. 09A-325-E

IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF COLORADO (A) FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE SAN LUIS VALLEY-CALUMET-COMANCHE TRANSMISSION PROJECT; (B) FOR SPECIFIC FINDINGS WITH RESPECT TO EMF AND NOISE, AND (C) FOR APPROVAL OF OWNERSHIP INTEREST TRANSFER AS NEEDED WHEN PROJECT IS COMPLETED.

RESPONSE OF TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC. TO FIRST SET OF INTERROGATORIES OF BLANCA RANCH HOLDINGS, LLC AND TRINCHERA RANCH HOLDINGS, LLC

Tri-State Generation and Transmission Association, Inc. ("Tri-State"), pursuant to Rule 1405 of the Rules of Practice and Procedure of the Colorado Public Utilities Commission, hereby responds to the First Set of Interrogatories of Blanca Ranch Holdings, LLC and Trinchera Ranch Holdings, LLC (collectively "Trinchera Ranch" or "TR") to Tri-State Generation and Transmission Association, Inc. as follows:[1]

TRINCHERA RANCH 3-1: Explain the Company's method of calculating the "Cost per MW" figures in Table 3-5 on page 3-13 of the June 2008 San Luis Valley Electric System Improvement Project Alternative Evaluation and Macro Corridor Study and identify the source of information used in said calculation.

ANSWER TO TRINCHERA RANCH 3-1:

[1] Trinchera Ranch's First Set of Interrogatories to Tri-State are, in fact, the third set of discovery requests submitted by Trinchera Ranch to Tri-State. Accordingly, for purposes of differentiating Tri-State's answers to these interrogatories from its answers to such earlier discovery requests, Tri-State's present answers will refer to, for example, "Trinchera Ranch 3-1" and "Answer to Trinchera Ranch 3-1".

{00711999 / 1}

The "Cost per MW" figures in Table 3-5 on page 3-13 of the June 2008 San Luis Valley Electric System Improvement Project Alternative Evaluation and Macro Corridor Study (the "2008 Study") were taken directly from the January 2004 PV Study Report (TSGT 000791-000848) with the exception of the connection from the San Luis Valley Substation to Walsenburg Substation. Tri-State has reexamined the "Cost per MW" calculation contained in the 2008 Study for the San Luis Valley Substation to Walsenburg alternative ($208,433) and determined that an error was made in the calculation. Since Tri-State installed certain equipment at the Walsenburg Substation in 2007 (a 230 kV circuit breaker, a 115 kV circuit breaker, and a 230/115 kV transformer), those costs should not have been included in the 2008 Study. The additional costs should have been limited to one additional 230 kV circuit breaker at the San Luis Valley Substation and one 230 kV circuit breaker at the Walsenburg Substation ($719,000 each). Given a seventy-five (75) mile long line at a cost of $400,000 per mile, plus the additional cost of the two circuit breakers, the correct value for the "Cost per MW" of the San Luis Valley – Walsenburg alternative in Table 3-5 is (75 miles x $400,000/mile) + $719,000 + $719,000/144 MW = $218,319.

Sponsor: Andrew R. Leoni

TRINCHERA RANCH 3-2: Explain the Company's method of calculating the "Cost per - MW" figures in Table 2 on page 7 of the January 2004 PV Study Report, San Luis Valley Substation Second 230 kV Source, and identify the source of data used in said calculation.

ANSWER TO TRINCHERA RANCH 3-2:

The "Cost per MW" figures in Table 2 on page 7 of the January 2004 PV Study Report, San Luis Valley Substation Second 230 kV Source are calculated by first adding the cost of the equipment required as shown in the tables on TSGT 000823-000827. This total cost for each alternative was then divided by the incremental increase of single contingency capability (in MW) included on the same Table 2 on page 7 to give a "Cost per MW". The source of data in the calculation is unit costs provided on TSGT 00082, and single contingency capability provided by study results in Table 1 on page 5 of the same report (TSGT 000796).

Sponsor: Andrew R. Leoni

TRINCHERA RANCH 3-3: What is (i) the single contingency load serving capability (in megawatts), (ii) the incremental increase in single contingency line capacity (in megawatts), and (iii) the cost per megawatt of incremental increase in single contingency capability, for the proposed double-circuit 230 kV transmission line from the San Luis Valley Substation to the proposed Calumet Substation?

ANSWER TO TRINCHERA RANCH 3-3:

Tri-State has not performed the analysis required to respond to the questions posed.

Sponsor: Andrew R. Leoni

{00711999 / 1}

TRI-STATE GENERATION AND
TRANSMISSION ASSOCIATION, INC.

Joel K. Bladow

Joel K. Bladow, Senior Vice President,
Transmission

STATE OF COLORADO)
) ss:
COUNTY OF ADAMS)

Before me, the undersigned authority, personally appeared Joel Bladow, _______________ of Tri-State Generation and Transmission Association, Inc., who acknowledged before me that the information contained in the foregoing Responses to First Set of Discovery Requests of The Colorado Office of Consumer Counsel is true and correct to the best of his knowledge, information and belief.

WITNESS my hand and official seal this 17th day of August, 2009.

Debbie Golinski

Notary Public, State of Colorado

My Commission Expires 08/21/2010

{00708559 / 1}

AS TO OBJECTIONS:

Kent L. Singer

Kent L. Singer, #15234
1801 Broadway, Suite 1100
Denver, Colorado 80202
(303) 292-0110
Facsimile: 303-292-0522
Email: kentsinger@aol.com

Thomas J. Dougherty, #30954
Email: tdougherty@rothgerber.com
Tamara F. Goodlette, #35775
Email: tgoodlette@rothgerber.com
Rothgerber Johnson & Lyons LLP
1200 17th Street, Suite 3000
Denver, Colorado 80202
(303) 623-9000
Facsimile: 303-623-9222

Kenneth V. Reif, #10666
Tri-State Generation & Transmission
Association, Inc.
P.O. Box 33695
Denver, Colorado 80233
(303) 452-6111
Facsimile: 303-254-6007
Email: kreif@tristategt.org

Attorneys for Applicant Tri-State Generation and Transmission Association, Inc.

{00708559 / 1}